Air Quality Permitting
Statement of Basis

September 29, 2005

Tier I Operating Permit No. T1-050308

Basic American Foods
Blackfoot, ID

Facility ID No. 011-00012

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FINAL TIER OPERATING PERMIT

Table of Contents

Acronyms, Units, and Chemical Nomenclatures

AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
BAF	Basic American Foods
Btu	British thermal unit
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
CMS	Continuous Monitoring Systems
COMS	Continuous Opacity Monitoring System
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
gr	grain (1 lb = 7,000 grains)
HAPs	Hazardous Air Pollutants
IDAPA	A numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pound per hour
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMscf	million standard cubic feet
NESHAP	Nation Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
PM_{10}	Particulate Matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	Prevention of Significant Deterioration
PTC	Permit to Construct
Rules	*Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01*
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
TPY or T/yr	Tons per year
UTM	Universal Transverse Mercator
VOC	volatile organic compound
ug/m^3	micrograms per cubic meter

Public Comment / Affected States / EPA Review Summary

A 30-day public comment period for the BAF Blackfoot facility draft Tier I operating permit was held from August 10, 2005 through September 8, 2005 in accordance with IDAPA 58.01.01.364, *Rules for the Control of Air Pollution in Idaho.*

IDAPA 58.01.01.008.01 defines *affected states* as: *"All states: whose air quality may be affected by the emissions of the Tier I source and that are contiguous to Idaho; or that are within 50 miles of the Tier I source."*

A review of the site location information included in the permit application indicates that the facility is not located within 50 miles of a state border, however, it is located within 50 miles of the Shoshone-Bannock Tribes. Therefore, the Shoshone-Bannock Tribes were also provided an opportunity to comment on the draft Tier I operating permit during the comment period.

Summary of Comments:

No comments were received from any member of the public, any tribe or affected state.

A hearing was not requested.

After the public comment period and/or public hearing, EPA was sent the proposed operating permit and the statement of basis for their 45 day review period. EPA did not provide any comments on the permit.

1. PURPOSE

The purpose for this memorandum is to satisfy the requirements of IDAPA 58.01.01.200, *Rules for the Control of Air Pollution in Idaho (Rules),* for issuing permits to construct (PTC) and IDAPA 58.01.01.300 for issuing Tier I operating permits..

2. FACILITY DESCRIPTION

The Basic American Foods (BAF) Blackfoot Plant includes a food dehydrating plant and a co-located research and development laboratory related to vegetable dehydrating and product development. The Blackfoot plant produces dehydrated food products using a variety of drying and dehydration processes. Products are dried by contact with heated air. Drying air is heated either by direct-firing with natural gas or indirectly using steam heat exchangers. Steam for plant operations is provided by Boiler Numbers 1, 2 and 3.

Note that BAF identifies the Blackfoot Plant boilers differently for plant operating purposes than the designations used in previous permits and in the current application. To minimize confusion, BAF has requested that the Department of Environmental Quality (DEQ) use the plant boiler numbering system. This permit and statement of basis use the revised numbering system. The revisions in boiler numbering are as follows:

Table 2.1 BOILER DESIGNATIONS

Previous Designation	Current Designation
Boiler 6	Boiler 2
Boiler 7	Boiler 3
Boiler 8	Boiler 1

3. FACILITY / AREA CLASSIFICATION

The BAF Blackfoot Plant is a major facility under the Title V program, as defined under IDAPA 58.01.01.008.10, because the facility emits or has the potential to emit a regulated air pollutant in amounts greater than 100 tons per year. The BAF Blackfoot Plant is not a major facility under the PSD/NSR program as defined under IDAPA 58.01.01.205.01 (40 CFR 52.21(b)(1)). The AIRS classification for this facility is "A" and the AIRS data entry table is provided in Appendix A.

The facility is located within AQCR 61 and UTM zone 12. The facility is located in Bingham County which is designated as attainment or unclassifiable for all criteria pollutants (CO, NO_x, SO_2, lead, and ozone). The Blackfoot Plant SIC is 2034 which represents establishments primarily engaged in artificially dehydrating fruits and vegetables, including "potato flakes, granules, and other dehydrated potato products."

4. APPLICATION SCOPE

4.1 Scope Summary

On February 4, 2005 DEQ received an application from BAF to modify Permit to Construct No. P-040300, issued March 22, 2004, as amended by Consent Order between Idaho DEQ and Basic American Foods in Case No. E-010007, dated August 20, 2004. The changes requested by this application involve only Boilers 1 and 2. No physical changes or changes in method of operation are proposed for Boiler 3. Changes are proposed as follows:

- Modify Boiler 2 for combustion of higher sulfur fuel including No. 6 residual oil
- Increase the allowable sulfur content of residual oil for Boiler 1 from 1.5% to 1.75%
- Increase the annual quantity of residual oil that may be combusted in Boiler 1
- Provide wet scrubbing treatment of the exhausts from Boilers 1 and 2 when combusting fuel oil to meet NSPS requirements for Boiler 2, and to reduce emissions of PM_{10}, SO_2, soluble acid gases and TAPs from Boilers 1 and 2
- Install ducting to merge the exhausts from Boilers 1 and 2 when fuel oil is combusted
- Replace limitations on hours of operation when combusting oil with fuel consumption limits for Boilers 1 and 2
- Establish enforceable limits on boiler house PTE so the entire facility remains minor for PSD purposes
- Revise boiler emission limits, operating, monitoring, recordkeeping and reporting requirements commensurate with this modification

4.2 Application Chronology

February 4, 2005	DEQ received the PTC application
February 18, 2005	DEQ received a 15-day pre-permit construction approval request
March 4, 2005	DEQ determined the PTC application was complete
March 9, 2005	DEQ approved the 15-day pre-permit construction approval request
March 15, 2005	DEQ received a Tier I Significant Permit Modification application
April 25, 2005	DEQ received amended application materials
April 27, 2005	DEQ received proposed PTC conditions from BAF
May 4, 2005	DEQ received a proposed Statement of Basis from BAF
June 7, 2005	DEQ received revisions to the TAPs compliance demonstration
June 24, 2005	DEQ issued a draft PTC and Statement of Basis to BAF for review
July 8 & 11, 2005	BAF provided comments regarding the draft permit
August 10, 2005	The public comment period was held August 10, 205 - September 9, 2005
September 16, 2005	Final PTC No. P-050301 was issued for the boiler modifications
September 20, 2005	DEQ provided a Proposed Tier I permit to EPA for review

5. PERMIT ANALYSIS

This section of the Statement of Basis describes the regulatory requirements for this PTC action.

5.1 Equipment List

Table 5.1 lists all sources affected by this permit modification.

Table 5.1 SUMMARY OF REGULATED SOURCES

Source Description	Emissions Control(s)
Boiler 1 (formerly Boiler 8): Manufacturer/Model: Murray Rated Heat Input: 57 MMBtu/hr Steam Rate: 45,500 lb/hr Fuels: natural gas, distillate and residual fuel oils	Wet Scrubber, Good Combustion Control
Boiler 2 (formerly Boiler 6): Manufacturer/Model: Johnson "509" Series, Model TF1800 – 3HG250S Rated Heat Input: 75.4 MMBtu/hr Steam Rate: 62,100 lb/hr Fuels: natural gas, distillate and residual fuel oils	Wet Scrubber, Good Combustion Control
Boiler 3 (formerly Boiler 7): Manufacturer/Model: Springfield Model 52 Rated Heat Input: 39 MMBtu/hr Steam Rate: 30,000 lb/hr Fuels: natural gas and low sulfur (0.05 wt %) distillate fuel oil	Good Combustion Control

5.2 *Emissions Inventory*

BAF's emissions inventory calculations take consideration of each of the following boiler firing scenarios and the project's estimated emissions are based on the scenario that yields the highest emissions for each pollutant:

- Firing Boilers 1 and 2 with No. 6 oil at reduced daily and annual heat input rates.
- Firing Boiler 2 on No. 2 oil at full firing rates for 8760 hours per year, and operating either Boiler 1 or Boiler 3 as a second boiler, selecting the particular combination of boiler and fueling option that yields the highest emissions for each pollutant.
- Firing Boiler 2 on natural gas at full firing rates for 8760 hours per year, and operating either Boiler 1 or Boiler 3 as a second boiler, selecting the particular combination of boiler and fueling option that yields the highest emissions for each pollutant.

Different scenarios were found to result in the highest estimated emissions. For example, natural gas firing is associated with the highest estimates for CO and VOC emissions, whereas No. 6 oil firing yields the highest estimated emissions of NO_x, PM_{10}, and SO_2.

The changes in emissions associated with this permit modification were estimated by the applicant and checked by DEQ. To determine the changes in criteria emissions for this project, the maximum emissions estimates provided in Tables 6 and 7 of the application were compared to the emission limits specified in the Appendix of PTC No. P-040300 issued on March 22, 2004. The criteria emissions changes are summarized below in Table 5.2. Estimates are only provided for Boilers 1 and 2, and not for Boiler 3, because emissions from Boiler 3 remain unchanged as part of this project. For convenient reference, copies of Tables 6, 7, 12, F-1, F-2, and F-3 from the application and the emission limits table in PTC No. P-040300 (March 22, 2004) are provided in Appendix B in addition to the DEQ emission estimate worksheets for this modification.

Table 5.2 EMISSION INVENTORY – MODIFICATION CHANGES

Pollutant	Hourly Emission Rate (lb/hr)					Annual Emissions (T/yr)				
	Existing[1]		Proposed[2]			Existing[1]		Proposed[2]		
	Boiler 1	Boiler 2	Boiler 1	Boiler 2	Change	Boiler 1	Boiler 2	Boiler 1	Boiler 2	Change
CO	1.3	3.3	4.6	6.1	6.1	4.5	8.4	19.9	26.5	33.5
NO_x	12.5	1.8	23.1	38.8	47.6	46.4	4.6	88.6	109.4	147
PM_{10}	3.3	0.1	2.1	3.6	2.3	12.1	0.3	8.2	10.1	5.9
SO_2	56.8	0.0	16.9	28.4	-11.5	205	0.1	64.8	80.1	-60.2
VOC	0.2	0.2	0.3	0.4	0.3	0.3	0.5	1.3	1.7	2.3

1. Existing emission based on estimated current emissions.
2. Proposed emission limits considering controls, restrictions on operations, and values for which compliance with applicable rules was demonstrated.

Table 5.3 summarizes total estimated facility-wide annual emissions from non-fugitive emissions units after the modification.

Table 5.3 EMISSION INVENTORY – ENTIRE FACILITY[1]

CO (T/yr)	NO_x (T/yr)	PM_{10} (T/yr)	SO_2 (T/yr)	VOC (T/yr)
231	235	138	160	6.6

[1] Excluding plant heater fugitive emissions (per 40 CFR 52.21(b)(1)(iii))

The increase in toxic air pollutant (TAP) emissions for this modification were also estimated by BAF and checked by DEQ. For this project, Table 5.4 provides a list of each TAP for which the estimated emissions increase is greater than the screening emission level (EL) listed in IDAPA 58.01.01.585 or 586. As described above, the maximum TAP increase is based on the boiler firing scenario that yields the highest emissions for each pollutant. For details, refer to application Tables 18-21 which are included in Appendix B. Also, refer to the modeling section or IDAPA 58.01.01.210 in the regulatory analysis section of this document.

Table 5.4 SUMMARY OF TAP EMISSION INVENTORY

TAP	EL (lb/hr)	Maximum Emission Rate (lb/hr)	
		Uncontrolled	Project Increase
Arsenic	1.50E-06	8.57E-04	1.19E-04[a]
Beryllium	2.80E-05	3.73E-04	1.80E-04[a]
Cadmium	3.70E-06	3.73E-04	4.34E-05[a]
Chromium (VI)	5.60E-07	1.61E-04	2.08E-05[a]
Nickel	2.70E-05	5.48E-02	8.14E-03[a]
Polycyclic Organic Matter (POM)	2.00E-06	7.79E-06	5.06E-06[a]
Formaldehyde	5.10E-04	4.36E-02	3.04E-02[a]
Chloride (as HCl)	5.00E-02	2.51E-01	---[b]
Vanadium (as V2O5)	3.00E-03	3.69E-02	5.54E-03[a]

a. Project increase is greater than EL.
b. No increase in emissions.

5.3 Modeling

Emissions increases associated with this project were modeled by the applicant in accordance with the State of Idaho Air Quality Modeling Guidance to demonstrate compliance with the NAAQS and TAP requirements under IDAPA 58.01.01.203. The applicant's analysis was reviewed and found to be consistent with DEQ methods and procedures. Details are provided in the Memorandum from Kevin Schilling to Dan Pitman which is included in Appendix C.

5.4 Regulatory Review

This section describes the regulatory analysis of the applicable air quality rules.

IDAPA 58.01.01.201 .... Permit to Construct Required

A permit to construct is required. This project does not qualify under the PTC exemption requirements. On this basis, BAF has applied for a PTC modification.

IDAPA 58.01.01.203.02 .... Demonstration of Preconstruction Compliance with NAAQS

Compliance with the NAAQS has been demonstrated in the permit application. Refer to the Modeling Section above and Appendix C for details.

IDAPA 58.01.01.205 .... Permit Requirements for New Major Facilities or Major Modifications in Attainment or Unclassifiable Areas

BAF is not a major facility for purposes of the NSR/PSD program as defined under IDAPA 58.01.01.205.01 [40 CFR 52.21(b)(1)(i)(a), (b) and (c)], as described below.

Because the facility is not on the list of sources stationary sources specified in 40 CFR 52.21(b)(1)(i) (i.e., the sources that have a PSD threshold of 100 TPY), the PSD threshold for the facility is 250 TPY. From Table 5.3 above, the pollutants with the highest PTE (at this facility are CO (231 TPY), NO_x (235 TPY) and SO_2 (160 TPY). These PTE estimates exclude fugitive emissions such as the plant heaters per 40 CFR 52.21(b)(1)(iii).

This boiler modification project does not constitute a "major modification" for purposes of the NSR/PSD program. The major modification definition given by 40 CFR 52.21(b)(2) does not apply since BAF is not a "major facility", for purposes of the NSR/PSD program, as described above.

IDAPA 58.01.01.209.05 .... PTC Requirements for Tier I Sources; Tier I Modification

For Boiler 1, the new and revised applicable requirements contained in the final PTC may be incorporated into the Tier I permit during renewal in accordance with IDAPA 58.01.01.209.05.a.iv. BAF may construct the modifications to Boiler 1 prior to issuance of the PTC per IDAPA 58.01.01.209.05.a.ii and 213. BAF may commence operation of Boiler 1 with the modifications in place after issuance of the PTC so long as it does not violate any terms or conditions of the existing Tier I operating permit and such operation will comply with Subsection 380.02 per IDAPA 58.01.01.209.05.a.iii.

Regarding Boiler 2, the Tier I operating permit is being modified concurrently with issuance of this PTC because the modifications to Boiler 2, allowing the combustion of residual oil, require that the Tier I permit be modified before the modified operations begin. BAF may not commence operations of Boiler 2 using residual oil, nor combust distillate oil or natural gas in any manner not allowed by the existing Tier I permit until issuance of the modified Tier I permit. BAF has submitted an application for modification of the Tier I permit to incorporate the provisions of this PTC. Concurrent issuance of the Tier I and PTC will be conducted in accordance with 58.01.01.209.05.b.

IDAPA 58.01.01.203.03, 210 .... Demonstration of Preconstruction Compliance with Toxic Standards

Emission increases of TAPs from the project have been evaluated to demonstrate compliance with the TAP standards under IDAPA 58.01.01.210. The TAP were evaluated with regard to the increase in TAP emissions resulting from the modification. Most of the TAP increases were shown to be in compliance with IDAPA 58.01.01.210.05 since the uncontrolled hourly emissions rate would be less than the applicable screening emission level (EL) listed in Sections 585 and 586.

Table 5.4 above, lists each TAP increase which exceeds the EL. For the TAPs which exceed the EL, all except nickel were shown to be in compliance with IDAPA 58.01.01.210.06 since the uncontrolled ambient concentration at the point of compliance is less than the applicable acceptable ambient concentration listed in Sections 585 and 586. Nickel was shown to be in compliance with IDAPA 58.01.01.210.08 since the controlled ambient concentration at the point of compliance is less than the applicable acceptable ambient concentration listed in Sections 585 and 586. For nickel, an emission limit was included in the PTC as required by IDAPA 58.01.01.210.08.c.

IDAPA 58.01.01.213 .... Pre-Permit Construction

On February 18, 2005, DEQ received a 15-Day Pre-permit Construction Approval Application submitted by BAF pursuant to IDAPA 58.01.01.213. By letter dated March 9, 2005, DEQ approved BAF's pre-permit construction application.

IDAPA 58.01.01.380, 382 .... Changes to Tier I Operating Permits

A Tier I permit revision is required for changes that are not addressed or prohibited by the Tier I operating permit if such changes are modifications under any provision of Title I of the Clean Air Act. The modifications to Boiler 2 allowing it to combust residual oil or to combust distillate oil with sulfur content greater than 0.05 weight percent (wt%) or for periods longer than 1440 hrs/year are subject to 40 CFR 60, Subpart Dc. Accordingly, a Tier I permit revision is needed for these modifications to Boiler 2. On February 15, 2005, BAF submitted a properly certified request for a significant modification of the Tier I permit to incorporate provisions of this PTC.

IDAPA 58.01.01.590 .... Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

60.40c, Applicability. The provisions of Subpart Dc apply to Boiler 2 since the modification of the boiler would occur after June 9, 1989 and it has a maximum design heat input capacity that is less than 100 but greater than 10 MMBtu/hr. Subpart Dc does not apply to Boiler 1 since it was installed and equipped with burners to fire residual oil prior to the June 9, 1989 cutoff date for applicability of this subpart. Details are provided below regarding applicability of Subpart Dc to Boiler 2.

The Boiler 2 modification project would be a modification under 60.14(a) since it is a physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies. It is noted that the exception to the modification under 60.14(e)(4) does not apply since the existing facility was not designed to accommodate the alternative fuel (fuel oil) prior to the date the standards under Subpart Dc became applicable to the source type (September 12, 1990). Per 60.40c(b), it is noted that delegation of the requirements of 60.48c(a)(4) are retained by the EPA Administrator with regard to emerging control technology. Also, 60.40c(c) and (d) do not apply since the boiler is not used for combustion research.

60.42c, Standard for Sulfur Dioxide. Under the SO_2 emission standard given by 60.42c(d), Boiler 2 shall not emit SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or as an alternative the oil combusted shall not contain greater than 0.5 wt% sulfur. Also per 60.42c(d), the percent reduction requirements for SO_2 are not applicable to the boiler. Compliance with the fuel oil sulfur limits and emissions limits (but not the percent reduction requirements) given by 60.42c(d) shall be determined on a 30-day rolling average basis per 60.42c(g). Under 60.42c(h), when distillate oil is fired, the NSPS rules allow compliance with the NSPS emission limits or fuel oil sulfur limits to be determined based on a certification from the fuel supplier, as described under 60.48c(f)(1); however, the requirements of 60.42c(h) were not included in the permit because a CEMS must be used for SO_2 monitoring for all fuel oils to avoid triggering the CAM requirements (see 40 CFR 64 below). The SO_2 emission limits and fuel oil sulfur limits apply at all times, including periods of startup, shut down, and malfunction per 60.42c(i).

It is noted that only the heat input supplied to the affected facility from the combustion of oil is counted under this section. No credit is provided for the heat input to the boiler from wood or other fuels or for heat derived from exhaust gases from other sources per 60.42c(j). The requirements under 60.22c(a), (b), (c), (e), and (f) do not apply to the boiler since it will not combust either of the following: coal; or oil in combination with any other fuel.

60.43c, Standard for Particulate Matter. The PM emission limits under 60.43c(a) and (b), expressed in terms of ng/J (lb/MMBtu) do not apply since the boiler does not combust coal or wood. The opacity standard under 60.43c(c) applies, and it applies at all times, except during periods of startup, shut down, and malfunction per 60.43c(d).

60.44c, Compliance and Performance Test Methods and Procedures for SO_2. For Boiler 2, the following requirements apply: 60.44c(a), (b), (c), (d), (g), (h), and (j). However, 60.44c(h) was not included in the permit because monitoring using fuel supplier receipts under 60.42c(h) is not allowed to avoid triggering the CAM requirements. The following requirements do not apply since the boiler does not combust coal, it does not combust oil in combination with other fuels, and the percent sulfur reduction requirement does not apply: 60.44c(e), (f), and (i).

60.45c, Compliance and Performance Test Methods and Procedures for PM. In accordance with 60.45c(a) and (a)(8), BAF shall conduct an initial performance test as required under 60.8 and shall conduct subsequent performance tests as requested by the EPA Administrator to determine compliance with the standards using the following procedures and reference methods: Method 9 (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions. The requirements of 60.45c(a)(1) through (7) do not apply since the boiler is not subject to the PM emission limit/concentration standards under 60.43c. The requirements under 60.45c(b) do not apply since 60.43c(b)2) does not apply.

60.46c, Emission Monitoring for SO_2. For Boiler 2, the requirements under 60.46c(a) through (f) apply except for the following. The requirements of 60.46c(e) were not included in the permit because monitoring using fuel supplier receipts under 60.42c(h) is not allowed to avoid triggering the CAM requirements. Since the boiler is not subject to the percent reduction requirements for SO_2, BAF is not required to do the following: measurement of SO_2 concentrations and either oxygen or carbon dioxide concentrations at both the inlet and outlet of the SO_2 control device as described under 60.46c(a); meet the CEMS span requirements of 60.46c(c)(3).

60.47c, Emission Monitoring for PM. The continuous Opacity Monitoring System (COMS) requirements under 60.47c(a) and (b), or alternative methods approved by EPA under 60.13(i), apply.

60.48c, Reporting and Recordkeeping Requirements. The requirements under 60.48c(a) through (g), (i), and (j) apply except for the following. The requirements of 60.48c(f) were not included in the permit because monitoring using fuel supplier receipts under 60.42c(h) is not allowed to avoid triggering the CAM requirements. Since the boiler does not fire coal and it is not subject to the percent reduction requirements for SO_2, the requirements of 60.48c(e)(3) and 60.48c(f)(3) do not apply. 60.48c(f)(2) does not apply since 60.42c(h)(2) does not apply. 60.48c(h) does not apply since there are no limits on the annual capacity factor for any fuel or mixture of fuels.

40 CFR Part 64 .... Compliance Assurance Monitoring (CAM)

Boilers 1, 2, and 3 are exempt from the requirements under 40 CFR Part 64. Boiler 1 does not meet the applicability criteria and Boilers 1 and 2 are exempt under 64.2(b) since the Tier I permit will require the use of an SO_2 CEMS (i.e., a continuous compliance determination method) when combusting residual or distillate fuel oil. Details are provided below.

Applicability is evaluated on a pollutant-specific basis for each emissions unit as follows:

- Under 64.2(a)(1), Boilers 1, 2, and 3 are subject to the following emission limitations or standards: NAAQS for SO_2 and PM_{10}; IDAPA 58.01.01.676 (fuel burning equipment grain loading standard) for PM; and NSPS for SO_2 for Boiler 2.
- Under 64.2(a)(2), Boilers 1 and 2 each use a wet scrubbing control device to achieve compliance with the emission limitations and standards listed above for SO_2, PM_{10} and PM. Part 64 does not apply with regard to any other regulated air pollutants because the boilers do not use a control device to achieve compliance with any of the emission limitations or standards for those pollutants. Boiler 3 is not applicable to CAM for any pollutant since it does not use a control device to achieve compliance with the emission limits or standards.
- The criteria under 64.2(a)(3) is evaluated as follows:
    - First, the lowest pound per hour emission rate that would result in emissions over 100 TPY is determined as follows, based on operations of 8760 hr/yr:
    - 100 tons/yr = (x)(8760 hr/yr)(ton/2000 lb)
    - x = (100 tons/yr)(yr/8760 hr)(2000 lb/ton) = 22.8 lb/hr
    - Second, applicable sources are identified using the uncontrolled emission rates in Table 6 of the application. The only "pollutant-specific emissions units" which utilize emissions controls and which have "potential pre-control device emissions" greater than 100 TPY (i.e., 22.8 lb/hr) are Boilers 1 and 2 when firing either distillate or residual oil. Specifically, Boilers 1 and 2 are pollutant specific emissions units only with regard to SO_2 (i.e., not with regard to PM or PM_{10}) and only when firing either distillate or residual oil.
- The CAM exemption under 64.2(b)(1)(i) does not apply for Boiler 2 since NSPS Subpart Dc was proposed prior to November 15, 1990.
- The CAM exemption under 64.2(b)(1)(vi) applies to Boilers 1 and 2 with regard to SO_2 as long as the Tier I permit (i.e., Part 70 permit) specifies that an SO_2 CEMS or Method 6b (i.e., continuous compliance determination methods per 40 CFR 60 Subpart Dc) must be used whenever distillate or residual fuel oil is combusted. Distillate oil monitoring based on fuel sampling and receipts, which is allowed under 60.42c(g) and (h), are not considered to be a "continuous" compliance determination methods, and for this reason they are not included in the permit as allowable options under the NSPS requirements. If BAF later desires to use fuel sampling or receipts instead of the CEMS for monitoring distillate oil, a PTC modification would be necessary; this exemption from Part 64 would no longer apply and the CAM requirements would need to be addressed as part of that modification.

IDAPA 58.01.01.591 .... 40 CFR Part 61 and Part 63, NESHAP, MACT

No MACT or NESHAP rules apply because the Blackfoot Plant is not a major source of Hazardous Air Pollutant Emissions.

IDAPA 58.01.01.625 .... Visible Emissions

The opacity standard applies and it is included in the permit. Compliance will be demonstrated using the monitoring requirements that already exist in the Tier I permit and using the opacity compliance demonstration procedures required by 40 CFR 60 for Boiler 2.

IDAPA 58.01.01.676-677.................................... Fuel Burning Equipment, Particulate Matter

IDAPA 58.01.01.676 applies to both boilers because the input heat capacity of each boiler is greater than 10 MMBtu/hr and both boilers were installed after October 1, 1979. Because of the potential for PM emissions from residual oil combustion, periodic testing of Boilers 1 and 2 using Method 5 is required by the permit to demonstrate compliance with this PM standard.

IDAPA 58.01.01.725-728.................................... Sulfur Content of Fuels

The maximum allowable sulfur content of fuel is 0.5 weight percent for distillate oil and 1.75 weight percent for residual oil. These limits of fuel sulfur content are included in the PTC and in the Tier I permit. Compliance is demonstrated by following the monitoring requirements based on fuel supplier records.

IDAPA 58.01.01.776... Control of Odors

Odor control requirements apply and they are already included in the facility's existing Tier I Operating Permit.

Consent Order E-010007, August 20, 2004......... Paragraph 13 Requirements

The application was submitted to meet the requirements of paragraph 13 of the Consent Order.

5.5 PTC Permit Conditions Review

This section describes only those permit conditions that have been revised, modified or deleted as a result of this permit action. All other permit conditions remain unchanged. Where permit condition numbers are given, these numbers correspond to the proposed modified PTC, unless stated otherwise.

Section 1. Permit to Construct Scope

Section 1, "Permit to Construct Scope," was updated to describe the modifications included in this permit.

Permit Condition 2.1

The emission rate limits for Boilers 1, 2 and 3 are revised to correspond to the information presented in the application which shows compliance with applicable rules such as the NAAQS. The limits are based on the worst case allowable operating scenario which is when Boilers 1 and 2 are fired at a reduced firing rate using No. 6 oil and Boiler 3 is not operated. Emission factors and stack combustion calculations when combusting fuel oil are the same for Boilers 1 and 2. Following is an example of how the combined boiler emissions limits were derived using information from Tables 6 and 7 of the application:

PM_{10} = 8.2 + 10.1 = 18.3 TPY
SO_2 = 64.8 + 80.1 = 145 TPY
CO = 19.9 + 26.5 = 46.4 TPY

Hourly emissions limits for Boiler 3 were not changed. Based on a review of controlled and uncontrolled emissions, the PM and VOC emission rate limits are not necessary for purposes of limiting PTE (e.g., for NAAQS, PSD threshold, etc.). Therefore, they are not included in the revised permit. The annual emissions limits for CO, PM_{10}, and SO_2 are based on "combined emissions" for all three boilers based on the estimates evaluated in the application. The NO_x emissions limit for Boilers 1 and 2 was also specified in terms of pounds per 1000 gallons for purposes of verifying the emissions rate limits for each boiler using the NO_x performance tests.

Compliance with all of these emission limits is demonstrated by complying with the boiler fuel throughput limits, annual operating schedules, tune-up and maintenance requirements as given in Section 3 of the PTC, and by complying with the monitoring requirements in Section 4 of the PTC to record the hours of operation and fuel use on a daily and monthly basis. Additional, specific operating, testing, monitoring and recordkeeping requirements are also included in Sections 3 and 4 for demonstrating compliance with the SO_2 and NO_x emissions limits.

Permit Condition 2.2

Permit Condition 2.2 incorporates the NSPS limits on sulfur dioxide emissions that are applicable to Boiler 2.

Compliance is determined from the NSPS operating, monitoring, recordkeeping and reporting requirements as provided in Sections 3-5 of the permit including use of an SO_2 CEMS.

Permit Condition 2.3 and 2.5

The Permit Conditions were changed to clarify the opacity requirements. No substantive changes were made.

Permit Condition 2.4

This condition was added to the permit to clarify the applicability of 40 CFR 60.13(g). When the exhausts from Boiler 1 and 2 are merged ahead of a single scrubber, and both boilers are subject to the same emission standards, BAF may install the continuous monitoring systems on each effluent or the combined effluent from Boilers 1 and 2.

Permit Condition 2.6

An annual emission limit is provided for nickel as required by IDAPA 58.01.01.210.08.c. Compliance with the emission limit is demonstrated by complying with the boiler fuel throughput limits and annual operating schedules as given in Section 3 of the PTC, and by complying with the monitoring requirements in Section 4 of the PTC to record the hours of operation and fuel use on a and monthly and annual basis.

Permit Condition 2.7

The PM standard for fuel burning equipment applies to Boilers 1, 2, and 3. PM emissions are reduced by the wet scrubbing system when oil is fired in Boilers 1 and 2. Compliance with this permit condition is assured by requirements to install and operate a wet scrubber when combusting fuel oil and to do periodic PM performance testing as required in Sections 3 and 4 of the PTC.

Permit Condition 2.8

BAF requested that boiler NO_x emission be limited to 198 TPY so that the plant will not become a major source under the PSD program as defined in IDAPA 58.01.01.205.01 [40 CFR 60 52.21(b)1)]. When allowable boiler NO_x emissions of 198 TPY are added to the 36.7 TPY potential to emit (PTE) from other point sources at the facility (not counting plant heaters which are fugitive sources), the plant-wide NO_x PTE is 235 TPY (198 + 36.7 = 235). This value provides a safety margin of 15 TPY to keep the facility below the PSD threshold of 250 TPY.

A reasonable demonstration that plant-wide NO_x emissions will remain below 250 TPY (i.e., below 235 TPY) is provided by demonstrating that the 198 TPY limit for the boilers is being met. This approach is based on the following assumptions: the three boilers are the predominant NO_x sources at the facility; there are numerous other NO_x sources at the plant but they are each small in comparison to the boilers; the NO_x PTE for those small units was conservatively estimated (based on uncontrolled PTE at 8760 hr/yr) and it is hr/yr) and it is reasonable to assume that actual operations/emissions from these sources will not exceed the PTE estimates. If an exceedance were to occur, it would most likely be caused by the boilers, therefore, a reasonable assurance that the 250 TPY threshold will not be exceeded is provided by using an emissions limit for the boilers plus operating, monitoring, recordkeeping and testing requirements to show compliance with this limit. This includes boiler fuel throughput limits, annual operating schedules, tune-up and maintenance requirements as given in Sections 3 and 4 of the PTC. These operating monitoring and recordkeeping requirements are adequate to make the boiler NO_x limit federally enforceable for PSD purposes.

As part of this compliance demonstration for the 198 TPY NO_x limit, periodic NO_x testing is required for Boilers 1 and 2 (the largest sources) but not for Boiler 3. The measured emission rates for Boilers 1 and 2 (expressed as lb/1000 gallons), and the PTE for Boiler 3 (i.e., 23 TPY) may be used to show compliance with the 198 TPY NO_x limit. Testing is not required for Boiler 3 because it is not changed as part of this modification and, more importantly, because the NO_x PTE is much smaller for Boiler 3 (i.e., 23 TPY) than the PTE is for Boilers 1 and 2 (i.e., 89 TPY and 109 TPY respectively). This is because Boiler 3 is fired primarily with natural gas, distillate oil use is limited, and residual oil use is prohibited.

<u>Permit Condition 3.1</u>

The demonstration of compliance with ambient air quality impact requirements incorporated assumptions from the application concerning the types of allowable fuels and the corresponding allowable sulfur contents for fuel oils. Permit Condition 3.1 incorporates these assumptions into the permit. The limits of 0.5 and 1.75 sulfur weight percent for distillate oil and residual oil combusted in Boilers 1 and 2 are the same as the maximum sulfur contents allowed by IDAPA 58.01.01, Sections 727 and 728.

<u>Permit Condition 3.2, 3.3, and 4.12</u>

The operating schedules and maximum fuel throughput rates included in the permit are the same as the assumptions used by BAF to demonstrate compliance with ambient air quality standards.

Operating limits are established for purposes of making the annual NO_x and CO emissions limits (for PSD threshold) and lb/hr PM_{10} emission limits (for NAAQS) federally and practically enforceable for Boilers 1, 2, and 3. Fuel throughput limits are established based on the quantity of residual fuel oil combusted that corresponds with the emissions limits under the worst case operating scenario (i.e., when Boilers 1 and 2 are fired with residual oil and Boiler 3 does not operate), as presented in the application. Fuel consumption limits for distillate oil and natural gas are not necessary since it was shown that emission rates, at near rated capacity, are considerably less for those fuels than for residual oil (i.e., residual oil is the worst case). The residual oil limits are determined as follows:

Annual fuel throughput limit for NO_x and CO:

NO_x = (96.64 lb/1000 gal)(X)(ton/2000 lb) = 198 tons/yr

X = (198 tons/yr)(1000 gal/96.64 lb)(2000 lb/ton) = 4,097,682 gal/yr

Short term fuel throughput limits for PM_{10}:

X = (239 gal/hr)(24 hr/day) = 5736 gal/day for Boiler 1

X = (402 gal/hr)(24 hr/day) = 9648 gal/day for Boiler 2

Since the emission factor is the same for both boilers, a combined fuel throughput limit of 15,384 gal/day is used in the permit (5736 + 9648 = 15,384).

The operating limits for Boiler 3, and corresponding monitoring in Section 4 of the permit, were changed so they are now based on fuel consumption instead of hours of operation. This change does not result in a change in operations for Boiler 3. The fuel consumption limits were determined as follows:

Distillate oil = (1440 hr/yr)(273 gal hr) = 393,120 gal yr

Natural gas = (8568 hr/yr)(39 MMBtu/hr)(scf/1020 Btu) = 328 MMscf/yr

Permit Condition 3.4

The compliance demonstration provided in the application (e.g., NAAQS) was based on a worst case operating scenario where Boilers 1 and 2 are operated at a reduced firing rate using No.6 oil, and Boiler 3 is not operated. This permit condition was established to ensure that the facility continues to operate in a manner that will not exceed this worst case scenario. However, it will also provide flexibility by allowing Boiler 3 to operate when Boilers 1 and 2 fire residual oil as long as firing of the boilers does not exceed the assumptions presented in the application (i.e., 15, 384 gal/day of No. 6 oil in Boilers 1 and 2 and 80,000 lbs-steam per hour from all three boilers).

Permit Condition 3.5, 3.6, and 3.7

The permit requires that wet scrubbing treatment be provided for the exhaust from Boiler 1 and Boiler 2 when fuel oil is combusted. When natural gas is combusted there is no requirement for wet scrubbing.

The requirement to install operate a wet scrubber(s) when combusting fuel oil is based on BAF's use of a wet scrubber in the application to demonstrate acceptable ambient impacts and compliance with the PM standard for fuel burning equipment (IDAPA 58.01.01, Section 676). To ensure proper operation of the scrubbing system, the permit requires that equipment be provided to monitor critical scrubber operating parameters. The permit also requires that an O&M manual be prepared for the scrubbing system and that the scrubber be operated and maintained in accordance with the plan.

With regard to merging the exhaust of Boilers 1 and 2, BAF's demonstration of compliance with ambient air quality impact requirements assumed that the exhaust from Boiler 2 would be merged with the exhaust from Boiler 1 whenever wet scrubbing was provided (i.e., whenever fuel oil was combusted in Boiler 2). The merged exhaust would then be discharged through the existing Boiler 1 stack. Because these operating conditions are part of BAF's NAAQS compliance demonstration, Permit Condition 3.5 requires that these exhausts be merged when wet scrubbing is provided.

Permit Condition 3.8

A permit condition requiring annual tune-up for each boiler was included in the previous permit as a method for demonstrating compliance with the emission limits that are based on efficient combustion practices. No substantive changes were made. provided.

Permit Conditions 3.9, 4.1, 4.2, 4.3, 4.4, 4.5, 4.10, 4.14, and 5.1

These permit conditions incorporate relevant portions of the NSPS compliance testing, monitoring, recordkeeping and reporting requirements that are applicable to sulfur dioxide and particulate emissions from Boiler 2 when combusting fuel oil. For sulfur dioxide, the permittee has the option of conducting monitoring either with a sulfur dioxide CEMS or by Method 6B. The PTC does not allow the permittee to monitor sulfur dioxide emissions using fuel supplier certification of distillate oil sulfur content for purposes of meeting the exemption requirements under 40 CFR 60 Part 64 (CAM).

For particulate matter, emission monitoring requires either a COMS or an approved alternate opacity monitoring plan. The NSPS requires a COMS, but COMS may not be a reliable monitoring method for exhaust that has been treated in a wet scrubber. Accordingly, Permit Condition 4.5 provides the permittee an option of developing an alternate opacity monitoring plan. The alternative opacity monitoring plan must be approved by EPA before being implemented. If approved, provisions of the alternate opacity monitoring plan will replace permit provisions requiring a COMS and appropriate provisions.

Permit Condition 4.6 and 5.2

For purposes of streamlining the demonstration of compliance with applicable requirements for Boiler 1, BAF has requested that Boiler 1 be subject to the same requirements for opacity and SO_2, including the NSPS requirements, that apply to Boiler 2. This will simplify permit compliance and allow the same instrumentation and controls to be used for both Boiler 1 and Boiler 2. The NSPS requirements provide an excellent method to demonstrate compliance with DEQ emission limits for opacity and sulfur dioxide.

Permit Condition 4.7 and 4.8

Periodic particulate matter performance testing while combusting No. 6 fuel oil, in conjunction with annual boiler tuning required by Permit Condition 3.8, is used to demonstrate compliance with the PM emission limits of IDAPA 58.01.01.676-677. An initial test for Boiler 2 is required within 60 days of reaching the maximum production rate with No. 6 oil or within 180 days of permit issuance. An initial test is not required for Boiler 1 since PM emissions will be reduced by the new scrubber and it was recently tested successfully using similar fuel (1.5% sulfur No. 6 oil) without the benefit of a control device. The next test for Boiler 1 is due within five years after this last PM test.

Permit Condition 4.9

NO_x performance testing while combusting fuel oil, in conjunction with an annual fuel throughput limit and annual boiler tuning requirements in Section 3, are used to demonstrate compliance with the 198 TPY NO_x limit for the boilers, and to show that plant-wide point source NO_x emissions will not exceed 250 TPY.

The difference between the facility-wide NO_x PTE of 235 tons per year and the regulatory threshold of 250 tons per year provides a margin of safety in emission estimates. In addition, by using NO_x emission factors that assume worst case fuel nitrogen content and that are significantly higher than AP-42 numbers, BAF has provided an additional margin of safety to assure that the 250 ton per year threshold is not exceeded. With these margins of safety, performance testing for NO_x emissions once every five years is satisfactory.

Permit Condition 4.11

This condition contains recordkeeping requirements which correspond to, and are used to demonstrate compliance with, the operating requirement to perform annual boiler tune-ups.

Permit Condition 4.12

Monitoring and recordkeeping of boiler operating parameters such as fuel consumption and steam production as required under the existing permit is continued in this permit.

Permit Condition 4.13

Fuel supplier sulfur content recordkeeping requirements of the existing PTC are included in this PTC and were changed to be consistent with the Tier I permit. This monitoring is required for purposes of showing compliance with IDAPA 58.01.01.725-728, not for NSPS purposes.

Permit Condition 4.15

Recordkeeping requirements were added that are consistent with Tier I permit requirements. This includes a five-year retention period.

Permit Condition 4.16

To demonstrate proper operation of the scrubbing system, the permit requires monitoring and recordkeeping of critical scrubber operating parameters to show the system is being operated in accordance with the manufacturers and O&M manual specifications.

Permit Condition 5.3

Performance test reports are to be submitted to DEQ within 60 days after completion of the test. This increases the time allowed for submission of the reports as compared with the existing permit. The added time is provided to allow additional time for reviewing the test report before submittal. The 60-day period also is consistent with changes that DEQ has previously agreed to provide for reporting under the facility Tier I permit.

5.5 *Tier I Permit Conditions Review*

This section describes only those Tier I permit conditions that have been revised, modified or deleted as a result of this permit action. All other permit conditions remain unchanged. Where permit condition numbers are given, these numbers correspond to the proposed modified Tier I, unless stated otherwise.

Permit Cover Page

Both the permit no. and the Facility ID no. were included. Also, the permittee name and the responsible official were corrected as presented in the application.

Section 1, Permit Scope

PTC No. P-050301 was added to Permit Conditions 1.2 and 1.3, and the emissions control information was revised for Boilers 1 and 2. In Table 1.1, the first column name was changed to be "Permit Section." Table 1.2, Monitoring and Reporting Summary, was deleted in lieu or revising it since it is not consistent with the facility-wide section and requirements summary table information negotiated between DEQ and EPA for Title V operating permits.

Section 3, Boilers 1, 2, and 3

The entire Section 3 was revised as follows. The summary description was changed to be consistent with the current Tier I format and the revised PTC. Existing Permit Conditions 3.1 through 3.20 were removed and replaced by the new PTC conditions. Each condition in PTC No. P-050301 is an applicable requirement, and it was added to Section 3 unless it is addressed elsewhere in the Tier I permit (e.g., in the Tier I Facility-wide or General Provisions sections). Refer to the PTC Permit Conditions Review section above for details. Table 3.3, the Applicable Requirements Summary, was also revised to incorporate the new PTC requirements.

Section 8, Nonapplicable Requirements

The acronym "CAM" was added to the permit's Acronym list and as follows: "Part 64 Compliance Assurance Monitoring (CAM)." The definition given by Reason Code "g" was changed to read as follows: "the facility does not have any emissions units which are subject to CAM requirements, as determined under 40 CFR 64.2".

General Provision 16

General Provision 16 was changed to refer to IDAPA 58.01.01.387 through 397 to be consistent with the latest rule revisions.

General Provision 21

General Provision 21.b was changed to reflect the actual Tier I Annual Compliance Certification schedule. General Provisions 21.d.ii and iii were revised to be consistent with the latest rule revisions.

General Provision 24

General Provision 24 was changed to reflect the actual Tier I Semiannual Monitoring Report schedule.

6. PERMIT FEES

DEQ received $7500.00 from BAF on February 6, 2005 and $1000.00 on July 22, 2005 for the PTC. Of this amount, $1000 was applied toward the PTC application fee and $7500.00 is applied toward the PTC processing fee in accordance with IDAPA 58.01.01.224-225. No additional PTC fees are due.

The BAF Blackfoot facility is a major facility as defined in IDAPA 58.01.01.008.10. Therefore, registration fees are applicable in accordance with IDAPA 58.01.01.387. As of July 12, 2005, no Tier I fees are overdue.

Table 6.1 PTC PROCESSING FEE TABLE

Fee Table			
Pollutant	**Annual Emissions Increase (T/yr)**	**Annual Emissions Reduction (T/yr)**	**Annual Emission Change (T/yr)**
NO_x	147	0	147
SO_2	0	60	-60
CO	34	0	34
PM	7	0	7
VOC	2	0	2
TAPS/HAPS	2	0	2
Total:	192	60	132
Fee Due	**$ 7,500.00**		

7. PERMIT REVIEW

7.1 Regional Review of Draft Permit

Copies of the facility-draft PTC and Statement of Basis were provided to the Pocatello Regional Office for review on May 27, 2005 and a response was received on June 3, 2005.

7.2 Facility Review of Draft Permit

Copies of the modified draft PTC and Statement of Basis were provided to BAF on June 24, 2005. Comments were received from BAF on July 8, 2005 and July 11, 2005. The documents, including the Tier I permit, were revised as appropriate and the changes are described in the Permit Conditions Review sections above.

7.3 *Public Comment*

A 30-day public comment period on the modified draft PTC and Tier I operating permit was held from August 10, 2005 through September 9, 2005 in accordance with IDAPA 58.01.01.209.05.b.iii and 58.01.01.364. A notice was published in the local newspaper and copies of the proposed action were placed in the local area in accordance with these rules. No comments were received. In addition, a proposed Tier I permit was provided to EPA Region 10 for the required review. No comments from EPA were received.

8. RECOMMENDATION

Based on review of application materials, and all applicable state and federal rules and regulations, staff recommend that Basic American Foods be issued Final Tier I Operating Permit No. T1-050308 for the Blackfoot facility. A comment period and EPA review have been completed and the project does not involve PSD requirements.

KH/sd Permit No. P-050301 and T1-050308

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Appendix A

AIRS Information

P-050301 and T1-050308

AIRS/AFS[a] FACILITY-WIDE CLASSIFICATION[b] DATA ENTRY FORM

Facility Name: Basic American Foods
Facility Location: Blackfoot
AIRS Number: 011-00012

AIR PROGRAM POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	SM80	TITLE V	AREA CLASSIFICATION A-Attainment U-Unclassified N- Nonattainment
SO_2	SM		X				SM	U
NO_x	A						A	U
CO	A						A	U
PM_{10}	A						A	U
PT (Particulate)	A		opacity				A	U
VOC	B						B	U
THAP (Total HAPs)	B						B	U
			APPLICABLE SUBPART					
			Dc					

[a] Aerometric Information Retrieval System (AIRS) Facility Subsystem (AFS)

[b] AIRS/AFS Classification Codes:

A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For HAPs only, class "A" is applied to each pollutant which is at or above the 10 T/yr threshold, or each pollutant that is below the 10 T/yr threshold, but contributes to a plant total in excess of 25 T/yr of all HAPs.

SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.

B = Actual and potential emissions below all applicable major source thresholds.

C = Class is unknown.

ND = Major source thresholds are not defined (e.g., radionuclides).

Appendix B

Emissions Inventory

P-050301 and T1-050308

Table 6
Criteria Pollutant Emission Rates

Fueling Option	Parameter	Boiler 6							Boiler 8						
		CO	NOx	SO2	PM	PM-10	VOC	Pb	CO	NOx	SO2	PM	PM-10	VOC	Pb
#6 Oil Firing	Emission Factor, lb/MMBTU	0.0904	0.663	1.941	0.143	0.123	0.0019	1.04E-05	0.0904	0.663	1.941	0.143	0.123	0.0019	1.04E-05
	Heat Rate, MMBTU/hr	58.6	58.6	58.6	58.6	58.6	58.6	58.6	34.8	34.8	34.8	34.8	34.8	34.8	34.8
	Uncontrolled Emission Rate, lb/hr	5.30	38.84	113.7	8.36	7.19	0.11	6.07E-04	3.15	23.08	67.6	4.97	4.27	0.07	3.61E-04
	Control Efficiency	0%	0%	75%	50%	50%	0%	50%	0%	0%	75%	50%	50%	0%	50%
	Controlled Emission Rate, lb/hr	5.30	38.84	28.4	4.18	3.59	0.11	3.03E-04	3.15	23.08	16.9	2.48	2.14	0.07	1.80E-04
#2 Oil Firing	Emission Factor, lb/MMBTU	0.0366	0.0731	0.515	0.0241	0.0121	0.0015	9.00E-06	0.0366	0.1462	0.515	0.0241	0.0121	0.0015	9.00E-06
	Heat Rate, MMBTU/hr	71.0	71.0	71.0	71.0	71.0	71.0	71.0	53.3	53.3	53.3	53.3	53.3	53.3	53.3
	Uncontrolled Emission Rate, lb/hr	2.59	10.38	36.6	1.71	0.86	0.10	6.39E-04	1.95	7.79	27.5	1.29	0.64	0.08	4.80E-04
	Control Efficiency	0%	0%	75%	50%	50%	0%	50%	0%	0%	75%	50%	50%	0%	50%
	Controlled Emission Rate, lb/hr	2.59	5.19	9.1	0.86	0.43	0.10	3.19E-04	1.95	7.79	6.9	0.64	0.32	0.08	2.40E-04
Natural Gas	Emission Factor, lb/MMBTU	0.0824	0.0550	0.002	0.0075	0.0075	0.0054	4.90E-07	0.0824	0.0980	0.002	0.0075	0.0075	0.0054	4.90E-07
	Heat Rate, MMBTU/hr	73.5	73.5	73.5	73.5	73.5	73.5	73.5	55.2	55.2	55.2	55.2	55.2	55.2	55.2
	Uncontrolled Emission Rate, lb/hr	6.06	4.04	0.2	0.55	0.55	0.40	3.60E-05	4.55	5.41	0.1	0.41	0.41	0.30	2.71E-05
	Control Efficiency	0%	0%	75%	0%	0%	0%	50%	0%	0%	75%	0%	0%	0%	50%
	Controlled Emission Rate, lb/hr	6.06	4.04	0.2	0.55	0.55	0.40	3.60E-05	4.55	5.41	0.1	0.41	0.41	0.30	2.71E-05
Maximum Hourly Emission Rate, lb/hr		6.06	38.84	28.4	4.18	3.59	0.40	3.19E-04	4.55	23.08	16.9	2.48	2.14	0.30	2.40E-04

Table 7
Estimated Plantwide Potential Emissions of Criteria Air Pollutants

Stack Identification	Estimated Annual Emissions, tons						
	CO	NOX	SO2	PM	PM-10	VOC	Lead
Boiler 6	26.5	106.8	78.2	11.5	9.9	1.7	1.40E-03
Boiler 7	-	-	-	-	-	-	-
Boiler 8	19.9	86.5	63.3	9.3	8.0	1.3	1.05E-03
DHQ	-	-	-	15.4	8.9	-	-
DHT	12.3	2.4	0.3	6.5	5.1	0.2	1.50E-05
DHU	12.3	2.4	0.3	6.5	5.1	0.2	1.50E-05
DHZ	6.8	1.3	0.5	10.7	7.6	0.1	1.29E-05
DKV	-	-	-	1.9	1.1	-	-
DKW	-	-	-	0.1	0.0	-	-
DXS	-	-	-	0.2	0.1	-	-
DUO	-	-	-	0.2	0.1	-	-
DPY	-	-	-	0.2	0.1	-	-
DPZ	-	-	-	0.2	0.1	-	-
DUQ	12.3	2.4	0.3	6.5	5.1	0.2	1.50E-05
DUT	12.3	2.4	0.3	6.5	5.1	0.2	1.50E-05
DUV	13.7	2.7	1.0	21.3	15.3	0.3	2.58E-05
DQA	12.3	2.4	0.3	6.5	5.1	0.2	1.50E-05
DQB	12.3	2.4	0.3	6.5	5.1	0.2	1.50E-05
DUY	-	-	-	0.1	0.1	-	-
DUZ	-	-	-	0.1	0.1	-	-
DSO	-	-	0.1	1.2	1.1	-	-
DSK	-	-	-	0.3	0.2	-	-
DUU	-	-	-	1.5	0.7	-	-
DRY	-	-	-	0.2	0.1	-	-
ALB	-	-	0.1	0.7	0.4	-	-
ALT	-	-	-	0.1	0.0	-	-
ALQ	-	-	0.1	0.4	0.3	-	-
ALY	-	-	-	0.0	0.01	-	-
ALX	-	-	-	0.1	0.1	-	-
ALV	-	-	0.1	1.1	0.7	-	-
ALW	-	-	0.1	0.6	0.5	-	-
AEV	3.8	0.7	0.1	0.7	0.5	0.1	7.09E-06

Table 7
Estimated Plantwide Potential Emissions of Criteria Air Pollutants

Stack Identification	Estimated Annual Emissions, tons						
	CO	NOX	SO2	PM	PM-10	VOC	Lead
EGT	-	-	-	0.4	0.2	-	-
FIF	-	-	-	1.7	0.4	-	-
CHK	-	-	-	0.7	1.0	-	-
CHI	-	-	-	0.7	1.0	-	-
Total Point Source Emissions	230.8	230.1	159.5	179.2	137.5	6.6	2.77E-03
Fugitive Dust	-	-	-	19.1	3.1	-	-
Heaters	13.2	15.7	0.4	1.2	1.2	0.9	7.87E-05
Total Fugitive Emissions	13.2	15.7	0.4	20.3	4.3	0.9	7.87E-05

Table 12

Proposed Emission Limits for Boilers 6, 7 and 8

Source Description	PM		PM-10		SO_2[1]		NOx[2]		VOC		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/hr
Boiler 6	4.3	18.7	3.7	16.1	28.4	124.5	26.1	114.4	0.40	1.7	6.1	26.5
Boiler 7	0.6	0.8	0.30	0.4	1.9	1.5	5.4	23.0	0.20	1.0	1.8	7.50
Boiler 8	2.5	10.9	2.1	9.4	16.9	74.0	15.5	67.9	0.30	1.3	4.6	19.9
Comments					Note 1	Note 1						

Notes:

1. SO_2 emission compliance while combusting fuel oil will be combined emissions from Boilers 6 and 7 measured using CEMS.
2. Combined NOx emissions from Boilers 6, 7, and 8 will not exceed 193 tons per year.

Table 18
Estimated Emissions of Toxic and Hazardous Air Pollutants and Comparison with TAP Screening Emission Levels – Fueling Option "#6 Oil - 1". Boilers 6 and 8 Firing #6 Oil

Air Pollutant	TAP Screening Emission Level, lb/hr	Uncontrolled Emissions, lb/hr				Scrubber Efficiency	Controlled Emissions, lb/hr			Net Emissions, lb/hr		
		Boiler 6	Boiler 8	Total	Exceeds Screening Emission Level?		Boiler 6	Boiler 8	Total	Current Emissions	Net Emissions Increase	Exceeds Screening Emission Level?
Arsenic	1.50E-06	5.42E-04	3.15E-04	8.57E-04	Yes	50%	2.71E-04	1.58E-04	4.28E-04	3.09E-04	1.19E-04	Yes
Barium	3.30E-02	1.05E-03	6.14E-04	1.67E-03	No	50%	5.27E-04	3.07E-04	8.34E-04	5.83E-04	2.51E-04	
Beryllium	2.80E-05	1.14E-05	6.64E-06	1.80E-05	No	50%	5.70E-06	3.32E-06	9.02E-06	6.89E-06	2.13E-06	
Cadmium	3.70E-06	1.63E-04	9.50E-05	2.58E-04	Yes	50%	8.16E-05	4.75E-05	1.29E-04	1.43E-04	-1.41E-05	No
Chloride (assume as HCl)	5.00E-02	1.42E-01	8.29E-02	2.25E-01	Yes	75%	3.56E-02	2.07E-02	5.63E-02	7.88E-02	-2.25E-02	No
Chromium	3.30E-02	3.47E-04	2.02E-04	5.48E-04	No	50%	1.73E-04	1.01E-04	2.74E-04	2.59E-04	1.52E-05	
Chromium (VI)	5.60E-07	1.02E-04	5.92E-05	1.61E-04	Yes	50%	5.09E-05	2.96E-05	8.05E-05	5.97E-05	2.08E-05	Yes
Cobalt	3.30E-02	2.47E-03	1.44E-03	3.91E-03	No	50%	1.23E-03	7.19E-04	1.95E-03	1.37E-03	5.83E-04	
Copper	1.30E-02	7.22E-04	4.20E-04	1.14E-03	No	50%	3.61E-04	2.10E-04	5.71E-04	4.00E-04	1.72E-04	
Fluoride	1.67E-01	1.53E-02	8.91E-03	2.42E-02	No	50%	7.65E-03	4.45E-03	1.21E-02	8.47E-03	3.64E-03	
Lead		6.19E-04	3.61E-04	9.80E-04		50%	3.10E-04	1.80E-04	4.90E-04	3.43E-04	1.47E-04	
Manganese	6.70E-02	1.23E-03	7.16E-04	1.95E-03	No	50%	6.15E-04	3.58E-04	9.74E-04	6.99E-04	2.74E-04	
Mercury	3.00E-03	4.64E-05	2.70E-05	7.33E-05	No		4.64E-05	2.70E-05	7.33E-05	3.82E-05	3.52E-05	
Molybdenum	3.33E-01	3.23E-04	1.88E-04	5.11E-04	No	50%	1.61E-04	9.40E-05	2.55E-04	1.79E-04	7.67E-05	
Nickel	2.70E-05	3.47E-02	2.02E-02	5.48E-02	Yes	50%	1.73E-02	1.01E-02	2.74E-02	1.93E-02	8.14E-03	Yes
Phosphorus	7.00E-03	3.88E-03	2.26E-03	6.14E-03	No	50%	1.94E-03	1.13E-03	3.07E-03	2.15E-03	9.22E-04	
Selenium	1.30E-02	2.80E-04	1.63E-04	4.43E-04	No	50%	1.40E-04	8.15E-05	2.22E-04	1.56E-04	6.55E-05	
Vanadium		1.30E-02	7.59E-03	2.06E-02		50%	6.52E-03	3.80E-03	1.03E-02	7.22E-03	3.10E-03	
Vanadium, as V2O5	3.00E-03	2.33E-02	1.36E-02	3.69E-02	Yes	50%	1.17E-02	6.78E-03	1.84E-02	1.29E-02	5.54E-03	Yes
Zinc	6.67E-01	1.19E-02	6.95E-03	1.89E-02	No	50%	5.97E-03	3.47E-03	9.44E-03	6.61E-03	2.84E-03	
Nitrous oxide	6.00E+00	4.51E-02	2.63E-02	7.14E-02	No		4.51E-02	2.63E-02	7.14E-02	2.50E-02	4.64E-02	

Table 19
Estimated Emissions of Toxic and Hazardous Air Pollutants and Comparison with TAP Screening Emission Levels – Fueling Option "#6 Oil - 6". Boiler 8 Firing #6 Oil and Boiler 7 Operating on #2 Oil or Natural Gas

		Uncontrolled Emissions, lb/hr						Controlled Emissions, lb/hr				Net Emissions, lb/hr		
Air Pollutant	TAP Screening Emission Level, lb/hr	Boiler 6	Boiler 7	Boiler 8	Total	Exceeds Screening Emission Level?	Scrubber Efficiency	Boiler 6	Boiler 7	Boiler 8	Total	Current Emissions	Net Emissions Increase	Exceeds Screening Emission Level?
POM		-	9.02E-04	2.87E-04	1.19E-03			-	9.02E-04	2.87E-04	1.19E-03	2.77E-04	9.12E-04	
Polyaromatic Hydrocarbons	9.40E-05	-	NA	1.46E-05	1.46E-05	No		-	NA	1.46E-05	1.46E-05	1.38E-05	7.19E-07	
POM (ID TAPs)	2.00E-06	-	NA	2.87E-06	2.87E-06	Yes		-	NA	2.87E-06	2.87E-06	2.72E-06	1.41E-07	No
Benz(a)anthracene		-	NA	9.58E-07	9.58E-07			-	NA	9.58E-07	9.58E-07	9.10E-07	4.72E-08	
Benzo(b,k)fluoranthene		-	NA	3.53E-07	3.53E-07			-	NA	3.53E-07	3.53E-07	3.36E-07	1.74E-08	
Chrysene		-	NA	5.68E-07	5.68E-07			-	NA	5.68E-07	5.68E-07	5.40E-07	2.80E-08	
Dibenzo(a,h) anthracene		-	NA	3.99E-07	3.99E-07			-	NA	3.99E-07	3.99E-07	3.79E-07	1.97E-08	
Indo(1,2,3-cd)pyrene		-	NA	5.11E-07	5.11E-07			-	NA	5.11E-07	5.11E-07	4.86E-07	2.52E-08	
Acenaphthene		-	NA	5.04E-06	5.04E-06			-	NA	5.04E-06	5.04E-06	4.79E-06	2.49E-07	
Acenaphthylene		-	NA	6.04E-08	6.04E-08			-	NA	6.04E-08	6.04E-08	5.74E-08	2.98E-09	
Anthracene		-	NA	2.91E-07	2.91E-07			-	NA	2.91E-07	2.91E-07	2.77E-07	1.44E-08	
Benzo(g,h,i)perylene		-	NA	5.40E-07	5.40E-07			-	NA	5.40E-07	5.40E-07	5.13E-07	2.66E-08	
Fluoranthene		-	NA	1.16E-06	1.16E-06			-	NA	1.16E-06	1.16E-06	1.10E-06	5.70E-08	
Fluorene		-	NA	1.07E-06	1.07E-06			-	NA	1.07E-06	1.07E-06	1.01E-06	5.27E-08	
Phenanthrene		-	NA	2.51E-06	2.51E-06			-	NA	2.51E-06	2.51E-06	2.38E-06	1.24E-07	
Pyrene		-	NA	1.01E-06	1.01E-06			-	NA	1.01E-06	1.01E-06	9.65E-07	5.01E-08	
Benzene	8.00E-04	-	8.01E-05	5.11E-05	1.31E-04	No		-	8.01E-05	5.11E-05	1.31E-04	1.76E-04	-4.47E-05	
Formaldehyde	5.10E-04	-	1.31E-02	1.01E-02	2.33E-02	Yes		-	1.31E-02	1.01E-02	2.33E-02	1.33E-02	1.00E-02	Yes
Toluene	2.50E+01	-	1.30E-04	1.48E-03	1.61E-03	No		-	1.30E-04	1.48E-03	1.61E-03	1.57E-03	3.94E-05	
ethyl benzene	2.90E+01	-	NA	1.52E-05	1.52E-05	No		-	NA	1.52E-05	1.52E-05	1.44E-05	7.49E-07	
o-Xylene	2.90E+01	-	NA	2.60E-05	2.60E-05	No		-	NA	2.60E-05	2.60E-05	2.47E-05	1.28E-06	
1,1,1-Trichloroethane	1.27E+02	-	NA	5.64E-05	5.64E-05	No		-	NA	5.64E-05	5.64E-05	5.36E-05	2.78E-06	
OCDD (adjusted to	1.50E-06	-	NA	7.40E-10	7.40E-10	No		-	NA	7.40E-10	7.40E-10	7.04E-10	3.65E-11	

Table 19
Estimated Emissions of Toxic and Hazardous Air Pollutants and Comparison with TAP Screening Emission Levels - Fueling Option "#6 Oil - 6". Boiler 8 Firing #6 Oil and Boiler 7 Operating on #2 Oil or Natural Gas

		Uncontrolled Emissions, lb/hr						Controlled Emissions, lb/hr				Net Emissions, lb/hr		
Air Pollutant	TAP Screening Emission Level, lb/hr	Boiler 6	Boiler 7	Boiler 8	Total	Exceeds Screening Emission Level?	Scrubber Efficiency	Boiler 6	Boiler 7	Boiler 8	Total	Current Emissions	Net Emissions Increase	Exceeds Screening Emission Level?
0.0001 TEF vs TCDD)														
Antimony	3.30E-02	-	NA	1.25E-03	1.25E-03	No	50%	-	NA	6.27E-04	6.27E-04	1.19E-03	-5.65E-04	
Arsenic	1.50E-06	-	1.50E-04	3.15E-04	4.65E-04	Yes	50%	-	1.50E-04	1.58E-04	3.07E-04	3.09E-04	-1.86E-06	No
Barium	3.30E-02	-	NA	6.14E-04	6.14E-04	No	50%	-	NA	3.07E-04	3.07E-04	5.83E-04	-2.77E-04	
Beryllium	2.80E-05	-	1.12E-04	6.64E-06	1.19E-04	Yes	50%	-	1.12E-04	3.32E-06	1.16E-04	6.89E-06	1.09E-04	Yes
Cadmium	3.70E-06	-	1.12E-04	9.50E-05	2.07E-04	Yes	50%	-	1.12E-04	4.75E-05	1.60E-04	1.43E-04	1.66E-05	Yes
Chloride (assume as HCl)	5.00E-02	-	NA	8.29E-02	8.29E-02	Yes	75%	-	NA	2.07E-02	2.07E-02	7.88E-02	-5.81E-02	No
Chromium	3.30E-02	-	1.12E-04	2.02E-04	3.14E-04	No	50%	-	1.12E-04	1.01E-04	2.13E-04	2.59E-04	-4.57E-05	
Chromium (VI)	5.60E-07	-	5.62E-06	5.92E-05	6.48E-05	Yes	50%	-	5.62E-06	2.96E-05	3.52E-05	5.97E-05	-2.44E-05	No
Cobalt	3.30E-02	-	3.21E-06	1.44E-03	1.44E-03	No	50%	-	3.21E-06	7.19E-04	7.22E-04	1.37E-03	-6.49E-04	
Copper	1.30E-02	-	2.25E-04	4.20E-04	6.45E-04	No	50%	-	2.25E-04	2.10E-04	4.35E-04	4.00E-04	3.53E-05	
Fluoride	1.67E-01	-	NA	8.91E-03	8.91E-03	No	50%	-	NA	4.45E-03	4.45E-03	8.47E-03	-4.01E-03	
Lead		-	NA	3.61E-04	3.61E-04		50%	-	NA	1.80E-04	1.80E-04	3.43E-04	-1.62E-04	
Manganese	6.70E-02	-	2.25E-04	7.16E-04	9.41E-04	No	50%	-	2.25E-04	3.58E-04	5.83E-04	6.99E-04	-1.16E-04	
Mercury	3.00E-03	-	1.12E-04	2.70E-05	1.39E-04	No		-	1.12E-04	2.70E-05	1.39E-04	3.82E-05	1.01E-04	
Molybdenum	3.33E-01	-	NA	1.88E-04	1.88E-04	No	50%	-	NA	9.40E-05	9.40E-05	1.79E-04	-8.47E-05	
Nickel	2.70E-05	-	1.12E-04	2.02E-02	2.03E-02	Yes	50%	-	1.12E-04	1.01E-02	1.02E-02	1.93E-02	-9.08E-03	No
Phosphorus	7.00E-03	-	NA	2.26E-03	2.26E-03	No	50%	-	NA	1.13E-03	1.13E-03	2.15E-03	-1.02E-03	
Selenium	1.30E-02	-	5.62E-04	1.63E-04	7.25E-04	No	50%	-	5.62E-04	8.15E-05	6.43E-04	1.56E-04	4.87E-04	
Vanadium		-	NA	7.59E-03	7.59E-03		50%	-	NA	3.80E-03	3.80E-03	7.22E-03	-3.42E-03	
Vanadium, as V2O5	3.00E-03	-	NA	1.36E-02	1.36E-02	Yes	50%	-	NA	6.78E-03	6.78E-03	1.29E-02	-6.11E-03	No
Zinc	6.67E-01	-	1.50E-04	6.95E-03	7.10E-03	No	50%	-	1.50E-04	3.47E-03	3.62E-03	6.61E-03	-2.98E-03	
Nitrous oxide	6.00E+00	-	3.01E-02	2.63E-02	5.63E-02	No		-	3.01E-02	2.63E-02	5.63E-02	2.50E-02	3.14E-02	

Table 20
Estimated Emissions of Toxic and Hazardous Air Pollutants and Comparison with TAP Screening Emission Levels – Fueling Option "#2 Oil - 1". Boilers 6 and 8 Firing #2 Oil

Air Pollutant	TAP Screening Emission Level, lb/hr	Uncontrolled Emissions, lb/hr					Controlled Emissions, lb/hr			Net Emissions, lb/hr		
		Boiler 6	Boiler 8	Total	Exceeds Screening Emission Level?	Scrubber Efficiency	Boiler 6	Boiler 8	Total	Current Emissions	Net Emissions Increase	Exceeds Screening Emission Level?
POM		1.71E-03	1.29E-03	3.00E-03			1.71E-03	1.29E-03	3.00E-03	2.77E-04	2.72E-03	
Formaldehyde	5.10E-04	2.49E-02	1.87E-02	4.36E-02	Yes		2.49E-02	1.87E-02	4.36E-02	1.33E-02	3.04E-02	Yes
Arsenic	1.50E-06	2.84E-04	2.14E-04	4.98E-04	Yes	50%	1.42E-04	1.07E-04	2.49E-04	3.09E-04	-6.03E-05	No
Beryllium	2.80E-05	2.13E-04	1.60E-04	3.73E-04	Yes	50%	1.07E-04	8.01E-05	1.87E-04	6.89E-06	1.80E-04	Yes
Cadmium	3.70E-06	2.13E-04	1.60E-04	3.73E-04	Yes	50%	1.07E-04	8.01E-05	1.87E-04	1.43E-04	4.34E-05	Yes
Chromium	3.30E-02	2.13E-04	1.60E-04	3.73E-04	No	50%	1.07E-04	8.01E-05	1.87E-04	2.59E-04	-7.22E-05	
Chromium (VI)	5.60E-07	1.07E-05	8.01E-06	1.87E-05	Yes	50%	5.33E-06	4.00E-06	9.34E-06	5.97E-05	-5.03E-05	No
Copper	1.30E-02	4.27E-04	3.20E-04	7.47E-04	No	50%	2.13E-04	1.60E-04	3.73E-04	4.00E-04	-2.61E-05	
Manganese	6.70E-02	4.27E-04	3.20E-04	7.47E-04	No	50%	2.13E-04	1.60E-04	3.73E-04	6.99E-04	-3.26E-04	
Mercury	3.00E-03	2.13E-04	1.60E-04	3.73E-04	No		2.13E-04	1.60E-04	3.73E-04	3.82E-05	3.35E-04	
Nickel	2.70E-05	2.13E-04	1.60E-04	3.73E-04	Yes	50%	1.07E-04	8.01E-05	1.87E-04	1.93E-02	-1.91E-02	No
Selenium	1.30E-02	1.07E-03	8.01E-04	1.87E-03	No	50%	5.33E-04	4.00E-04	9.34E-04	1.56E-04	7.77E-04	
Zinc	6.67E-01	2.84E-04	2.14E-04	4.98E-04	No	50%	1.42E-04	1.07E-04	2.49E-04	6.61E-03	-6.36E-03	
Nitrous oxide	6.00E+00	5.71E-02	4.29E-02	1.00E-01	No		5.71E-02	4.29E-02	1.00E-01	2.50E-02	7.50E-02	

Table 21
Estimated Emissions of Toxic and Hazardous Air Pollutants and Comparison with TAP Screening Emission Levels – Fueling Option "NG - 1". Boilers 6 and 8 Firing Natural Gas

Air Pollutant	TAP Screening Emission Level, lb/hr	Uncontrolled Emissions, lb/hr				Scrubber Efficiency	Controlled Emissions, lb/hr			Net Emissions, lb/hr		
		Boiler 6	Boiler 8	Total	Exceeds Screening Emission Level?		Boiler 6	Boiler 8	Total	Current Emissions	Net Emissions Increase	Exceeds Screening Emission Level?
POM		6.36E-06	4.78E-06	1.11E-05			6.36E-06	4.78E-06	1.11E-05	2.77E-04	-2.66E-04	
Benzene	8.00E-04	1.51E-04	1.14E-04	2.65E-04	No		1.51E-04	1.14E-04	2.65E-04	1.76E-04	8.93E-05	
Dichlorobenzene	2.00E+01	8.68E-05	6.52E-05	1.52E-04	No		8.68E-05	6.52E-05	1.52E-04	1.01E-04	5.11E-05	
Formaldehyde	5.10E-04	5.40E-03	4.06E-03	9.46E-03	Yes		5.40E-03	4.06E-03	9.46E-03	1.33E-02	-3.79E-03	No
Hexane	1.20E+01	1.29E-01	9.72E-02	2.27E-01	No		1.29E-01	9.72E-02	2.27E-01	1.50E-01	7.63E-02	
Toluene	2.50E+01	2.45E-04	1.84E-04	4.29E-04	No		2.45E-04	1.84E-04	4.29E-04	1.57E-03	-1.14E-03	
Arsenic	1.50E-06	1.44E-05	1.08E-05	2.52E-05	Yes	50%	7.21E-06	5.41E-06	1.26E-05	3.09E-04	-2.97E-04	No
Beryllium	2.80E-05	8.68E-07	6.52E-07	1.52E-06	No	50%	4.34E-07	3.26E-07	7.60E-07	6.89E-06	-6.13E-06	
Cadmium	3.70E-06	7.94E-05	5.96E-05	1.39E-04	Yes	50%	3.97E-05	2.98E-05	6.95E-05	1.43E-04	-7.38E-05	No
Chromium	3.30E-02	1.01E-04	7.56E-05	1.76E-04	No	50%	5.04E-05	3.78E-05	8.82E-05	2.59E-04	-1.71E-04	
Chromium (VI)	5.60E-07	5.04E-06	3.79E-06	8.83E-06	Yes	50%	2.52E-06	1.89E-06	4.42E-06	5.97E-05	-5.52E-05	No
Cobalt	3.30E-02	6.06E-06	4.55E-06	1.06E-05	No	50%	3.03E-06	2.27E-06	5.30E-06	1.37E-03	-1.37E-03	
Manganese	6.70E-02	2.74E-05	2.06E-05	4.80E-05	No	50%	1.37E-05	1.03E-05	2.40E-05	6.99E-04	-6.75E-04	
Mercury	3.00E-03	1.87E-05	1.41E-05	3.28E-05	No		1.87E-05	1.41E-05	3.28E-05	3.82E-05	-5.32E-06	
Nickel	2.70E-05	1.51E-04	1.14E-04	2.65E-04	Yes	50%	7.57E-05	5.69E-05	1.33E-04	1.93E-02	-1.91E-02	No
Selenium	1.30E-02	1.73E-06	1.30E-06	3.03E-06	No	50%	8.64E-07	6.49E-07	1.51E-06	1.56E-04	-1.55E-04	

Table F-1
Current Criteria Pollutant Emissions from Boilers 6

Air Pollutant	Emission Factor		Maximum Hour, lbs	Annual, tons
	Natural Gas, lb/MMBTU	Reference	Natural Gas Firing (Peak Day Heat Rate = 49.0 MMBTU/hr)	Natural Gas Firing (Annual Gas Use = 249,791 MMBTU)
CO	0.068	From Aug 2 1994 BAF Application for Permit to Construct: 5.1 lb CO/hr @ 75.4 MMBTU/hr	3.31	8.4
NOx	0.037	From Aug 2 1994 BAF Application for Permit to Construct: 2.8 lb NOx/hr @ 75.4 MMBTU/hr	1.82	4.6
SO2	0.0006	From Aug 2 1994 BAF Application for Permit to Construct: 0.2 tons SO2/yr @ 75.4 MMBTU/hr and 8568 hr/yr	0.03	0.1
PM	2.79E-03	From Aug 2 1994 BAF Application for Permit to Construct: 0.9 tons PM/yr @ 75.4 MMBTU/hr and 8568 hr/yr	0.14	0.3
PM-10	2.79E-03	All PM assumed to be PM-10;	0.14	0.3
VOC	4.02E-03	From Aug 2 1994 BAF Application for Permit to Construct: 1.3 tons VOC/yr @ 75.4 MMBTU/hr and 8568 hr/yr	0.20	0.5
Pb	4.90E-07	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.	2.40E-05	6.12E-05

Table F-2
Current Criteria Pollutant Emissions from Boiler 8

	Emission Factor - Natural Gas		Emission Factor - #6 Oil		Maximum Hour, lbs			Annual, tons		
Air Pollutant	Emission Factor, lb/MMBTU	Reference	Emission Factor, lb/kgal	Reference	#6 Oil Firing (Peak Day Heat Rate = 227 gal/hr)	Natural Gas Firing (Peak Day Heat Rate = 36.4 MMBTU/hr)	Maximum Hourly Emissions	#6 Oil Firing (Annual Oil Use = 1.64 MMgal)	Natural Gas Firing (Annual Gas Use = 19,142 MMBTU)	Total Annual Emissions
CO	0.036	From Aug 2 1994 BAF Application for Permit to Construct: 2.0 lb CO/hr @ 55.1 MMBTU/hr	5	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1.	1.14	1.32	1.32	4.10	0.347	4.45
NOx	0.138	From Aug 2 1994 BAF Application for Permit to Construct: 7.6 lb NOx/hr @ 55.1 MMBTU/hr	55	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1.	12.5	5.02	12.49	45.10	1.320	46.42
SO2	0.0004	From Aug 2 1994 BAF Application for Permit to Construct: 0.1 tons SO2/yr @ 55.1 MMBTU/hr and 8568 hr/yr	250	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1. 1.648 lbSO2/MMBTU and 151.8 MMBTU/kgal	56.8	0.015	56.8	205.00	0.004	205.00
PM	2.97E-03	From Aug 2 1994 BAF Application for Permit to Construct: 0.7 tons PM/yr @ 55.1 MMBTU/hr and 8568 hr/yr	17	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1.	3.88	0.108	3.88	14.02	0.028	14.05
PM-10	2.97E-03	All PM assumed to be PM-10;	15	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1.	3.34	0.108	3.34	12.05	0.028	12.08
VOC	5.51E-03	From Aug 2 1994 BAF Application for Permit to Construct: 1.3 tons VOC/yr @ 55.1 MMBTU/hr and 8568 hr/yr	0.28	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1.	0.064	0.200	0.20	0.23	0.053	0.28

Table F-2
Current Criteria Pollutant Emissions from Boiler 8

	Emission Factor - Natural Gas		Emission Factor - #6 Oil		Maximum Hour, lbs			Annual, tons		
Air Pollutant	Emission Factor, lb/MMBTU	Reference	Emission Factor, lb/kgal	Reference	#6 Oil Firing (Peak Day Heat Rate = 227 gal/hr)	Natural Gas Firing (Peak Day Heat Rate = 36.4 MMBTU/hr)	Maximum Hourly Emissions	#6 Oil Firing (Annual Oil Use = 1.64 MMgal)	Natural Gas Firing (Annual Gas Use = 19,142 MMBTU)	Total Annual Emissions
Pb	4.90E-07	Based on AP-42 emission factor of 0.0005 lbs Pb/MMscf of fuel combusted.	0.0015	From January 2004 BAF Application for Permit to Construct Boiler 8, Table 1.	3.43E-04	1.78E-05	3.43E-04	1.24E-03	0.000	0.00

Table F-3
Current TAP Emissions from Boilers 6 and 8

Air Pollutant			Boiler 6		Boiler 8						Combined Emissions from Boilers 6 and 8, lbs	
	Emission Factor		Maximum Hour, lbs	Annual, lbs	Maximum Hour, lbs			Annual, lbs				
Name	#6 Oil, lb/kgal	Natural Gas, lb/MMBTU	Natural Gas Firing (Peak Day Heat Rate = 49.0 MMBTU/hr)	Natural Gas Firing (Annual Gas Use = 249,791 MMBTU)	#6 Oil Firing (Peak Day Heat Rate = 227 gal/hr)	Natural Gas Firing (Peak Day Heat Rate = 36.4 MMBTU/hr)	Maximum Hourly Emissions	#6 Oil Firing (Annual Oil Use = 1.64 MMgal)	Natural Gas Firing (Annual Gas Use = 19,142 MMBTU)	Total Annual Emissions	Maximum Hour	Annual, lbs
POM	1.20E-03	8.65E-08	4.24E-06	0.022	2.72E-04	3.15E-06	2.72E-04	1.97	0.002	1.97	2.77E-04	1.99
Polyaromatic Hydrocarbons	6.10E-05	NA	NA	NA	1.38E-05	NA	1.38E-05	0.10	NA	0.10	1.38E-05	0.10
POM (ID TAPs)	1.20E-05	NA	NA	NA	2.72E-06	NA	2.72E-06	0.02	NA	0.02	2.72E-06	0.02
Benz(a)anthracene	4.01E-06	NA	NA	NA	9.10E-07	NA	9.10E-07	0.01	NA	0.01	9.10E-07	0.01
Benzo(b,k)fluoranthene	1.48E-06	NA	NA	NA	3.36E-07	NA	3.36E-07	0.00	NA	0.00	3.36E-07	0.00
Chrysene	2.38E-06	NA	NA	NA	5.40E-07	NA	5.40E-07	0.00	NA	0.00	5.40E-07	0.00
Dibenzo(a,h) anthracene	1.67E-06	NA	NA	NA	3.79E-07	NA	3.79E-07	0.00	NA	0.00	3.79E-07	0.00
Indo(1,2,3-cd)pyrene	2.14E-06	NA	NA	NA	4.86E-07	NA	4.86E-07	0.00	NA	0.00	4.86E-07	0.00
Acenaphthene	2.11E-05	NA	NA	NA	4.79E-06	NA	4.79E-06	0.03	NA	0.03	4.79E-06	0.03
Acenaphthylene	2.53E-07	NA	NA	NA	5.74E-08	NA	5.74E-08	0.00	NA	0.00	5.74E-08	0.00
Anthracene	1.22E-06	NA	NA	NA	2.77E-07	NA	2.77E-07	0.00	NA	0.00	2.77E-07	0.00
Benzo(g,h,i)perylene	2.26E-06	NA	NA	NA	5.13E-07	NA	5.13E-07	0.00	NA	0.00	5.13E-07	0.00
Fluoranthene	4.84E-06	NA	NA	NA	1.10E-06	NA	1.10E-06	0.01	NA	0.01	1.10E-06	0.01
Fluorene	4.47E-06	NA	NA	NA	1.01E-06	NA	1.01E-06	0.01	NA	0.01	1.01E-06	0.01
Phenanthrene	1.05E-05	NA	NA	NA	2.38E-06	NA	2.38E-06	0.02	NA	0.02	2.38E-06	0.02
Pyrene	4.25E-06	NA	NA	NA	9.65E-07	NA	9.65E-07	0.01	NA	0.01	9.65E-07	0.01
Benzene	2.14E-04	2.06E-06	1.01E-04	0.515	4.86E-05	7.50E-05	7.50E-05	0.35	0.039	0.39	1.76E-04	0.87
Dichlorobenzene	NA	1.18E-06	5.78E-05	0.295	NA	4.30E-05	4.30E-05	NA	0.023	0.02	1.01E-04	0.29
Formaldehyde	4.25E-02	7.35E-05	3.60E-03	18.360	9.65E-03	2.68E-03	9.65E-03	69.70	1.407	71.1	1.33E-02	88.06
Hexane	NA	1.76E-03	8.63E-02	439.633	NA	6.41E-02	6.41E-02	NA	33.689	33.7	1.50E-01	439.63
Toluene	6.20E-03	3.33E-06	1.63E-04	0.832	1.41E-03	1.21E-04	1.41E-03	10.17	0.064	10.23	1.57E-03	11.00
ethyl benzene	6.36E-05	NA	NA	NA	1.44E-05	NA	1.44E-05	0.10	NA	0.10	1.44E-05	0.10
o-Xylene	1.09E-04	NA	NA	NA	2.47E-05	NA	2.47E-05	0.18	NA	0.18	2.47E-05	0.18
1,1,1-Trichloroethane	2.36E-04	NA	NA	NA	5.36E-05	NA	5.36E-05	0.39	NA	0.39	5.36E-05	0.39
OCDD (adjusted to 0.0001 TEF vs TCDD)	3.10E-09	NA	NA	NA	7.04E-10	NA	7.04E-10	0.00	NA	0.00	7.04E-10	0.00
Antimony	5.25E-03	NA	NA	NA	1.19E-03	NA	1.19E-03	8.61	NA	8.61	1.19E-03	8.61
Arsenic	1.32E-03	1.96E-07	9.61E-06	0.049	3.00E-04	7.13E-06	3.00E-04	2.16	0.004	2.17	3.09E-04	2.21
Barium	2.57E-03	NA	NA	NA	5.83E-04	NA	5.83E-04	4.21	NA	4.21	5.83E-04	4.21
Beryllium	2.78E-05	1.18E-08	5.78E-07	0.003	6.31E-06	4.30E-07	6.31E-06	0.05	0.000	0.05	6.89E-06	0.05
Cadmium	3.98E-04	1.08E-06	5.29E-05	0.270	9.03E-05	3.93E-05	9.03E-05	0.65	0.021	0.67	1.43E-04	0.92
Chloride (assume as HCl)	3.47E-01	NA	NA	NA	7.88E-02	NA	7.88E-02	569.08	NA	569	7.88E-02	569.08
Chromium	8.45E-04	1.37E-06	6.72E-05	0.342	1.92E-04	4.99E-05	1.92E-04	1.39	0.026	1.41	2.59E-04	1.73
Chromium (VI)	2.48E-04	6.86E-08	3.36E-06	0.017	5.63E-05	2.50E-06	5.63E-05	0.41	0.001	0.41	5.97E-05	0.42
Cobalt	6.02E-03	8.24E-08	4.04E-06	0.021	1.37E-03	3.00E-06	1.37E-03	9.87	0.002	9.87	1.37E-03	9.89
Copper	1.76E-03	NA	NA	NA	4.00E-04	NA	4.00E-04	2.89	NA	2.89	4.00E-04	2.89
Fluoride	3.73E-02	NA	NA	NA	8.47E-03	NA	8.47E-03	61.17	NA	61.17	8.47E-03	61.17
Lead	1.51E-03	NA	NA	NA	3.43E-04	NA	3.43E-04	2.48	NA	2.48	3.43E-04	2.48
Manganese	3.00E-03	3.73E-07	1.83E-05	0.093	6.81E-04	1.36E-05	6.81E-04	4.92	0.007	4.93	6.99E-04	5.01
Mercury	1.13E-04	2.55E-07	1.25E-05	0.064	2.57E-05	9.28E-06	2.57E-05	0.19	0.005	0.19	3.82E-05	0.25
Molybdenum	7.87E-04	NA	NA	NA	1.79E-04	NA	1.79E-04	1.29	NA	1.29	1.79E-04	1.29
Nickel	8.45E-02	2.06E-06	1.01E-04	0.515	1.92E-02	7.50E-05	1.92E-02	138.58	0.039	138.6	1.93E-02	139.09
Phosphorus	9.46E-03	NA	NA	NA	2.15E-03	NA	2.15E-03	15.51	NA	15.51	2.15E-03	15.51
Selenium	6.83E-04	2.35E-08	1.15E-06	0.006	1.55E-04	8.55E-07	1.55E-04	1.12	0.000	1.12	1.56E-04	1.13
Vanadium	3.18E-02	NA	NA	NA	7.22E-03	NA	7.22E-03	52.15	NA	52.15	7.22E-03	52.15
Vanadium, as V2O5	5.68E-02	NA	NA	NA	1.29E-02	NA	1.29E-02	93.15	NA	93.15	1.29E-02	93.15
Zinc	2.91E-02	NA	NA	NA	6.61E-03	NA	6.61E-03	47.72	NA	47.72	6.61E-03	47.72
Nitrous oxide	1.10E-01	NA	NA	NA	2.50E-02	NA	2.50E-02	180.40	NA	180.4	2.50E-02	180.40

5. APPENDIX A

BASIC AMERICAN FOODS

Emission Limits[a] - Hourly (lb/hr) and Annual[b] (T/yr)

Source Description	PM		PM-10		SO_2		NO_x		VOC		CO	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/hr
Boiler #6	1.1	1.5	0.55	0.75	3.7	2.8	4.0	12.8	0.40	1.3	5.1	21.7
Boiler #7	0.6	0.8	0.30	0.40	1.9	1.5	5.4	23.0	0.20	1.0	1.8	7.50
Boiler #8	2.61	9.4	2.25	8.1	56.9	210	12.5	51.4	0.30	1.3	2.0	6.30

a As determined by a pollutant specific U.S. EPA reference method, or DEQ approved alternative, or as determined by DEQ's emission estimation methods used in this permit analysis.

b As determined by multiplying the actual or allowable (if actual is not available) pound per hour emission rate by the allowable hours per year that the process(es) may operate(s), or by actual annual production rates.

Emission Estimates: BAF Blackfoot, Boiler 1 (formerly Boiler 8), No. 6 Fuel Oil

DEQ Reviewer, Date: Ken Hanna, April 28, 2005
#6 Fuel Oil Combustion < 100 MMBtu/hr
Rated Input Capcity = 3.48E+07 Btu/hr
Actual Heat Input Rate = 3.59E+07 Btu/hr
Fuel usage rate = 239 gal/hr
Sulfur Content = 1.75 % by weight
Annual hours of operation= 8760

[redacted]							
SO_2	157*S[a]	65.7	288	75	1.64E+01	7.19E+01	
SO_3	2*S[a]	0.837	3.66				
NO_x	96.64	23.1	101.2				
CO	13.2	3.15	13.82				
PM Total	20.8	4.97	21.77	50	2.49E+00	1.09E+01	
PM-10	17.9	4.28	18.74	50	2.14E+00	9.37E+00	
VOC[b]	0.28	0.067	0.29				
Benzene	*2.14E-04*	*5.11E-05*	*2.24E-04*				
Ethylbenzene	6.36E-05	1.52E-05	6.66E-05				
Formaldehyde	4.25E-02	1.02E-02	4.45E-02				
Naphthalene	*1.13E-03*	*2.70E-04*	*1.18E-03*				
1,1,1-Trichloroethane	2.36E-04	5.64E-05	2.47E-04				
Toluene	6.20E-03	1.48E-03	6.49E-03				
o-Xylene	1.09E-04	2.61E-05	1.14E-04				
Acenaphthene	2.11E-05	5.04E-06	2.21E-05				
Acenaphthylene	2.53E-07	6.05E-08	2.65E-07				
Anthracene	1.22E-06	2.92E-07	1.28E-06				
Benz(a)anthracene[c]	4.01E-06	9.58E-07	4.20E-06				
Benzo(b,k)fluoranthene	*1.48E-06*	3.54E-07	1.55E-06				
Benzo(g,h,i)perylene	2.26E-06	5.40E-07	2.37E-06				
Chrysene[c]	2.38E-06	5.69E-07	2.49E-06				
Dibenzo(a,h)anthracene[c]	1.67E-06	3.99E-07	1.75E-06				
Fluoranthene	4.84E-06	1.16E-06	5.07E-06				
Fluorene	4.47E-06	1.07E-06	4.68E-06				
Indo (1,2,3-cd)pyrene[c]	2.14E-06	5.11E-07	2.24E-06				
PAH[d]	1.02E-05	2.44E-06	1.07E-05				
Phenanthrene	*1.05E-05*	*2.51E-06*	*1.10E-05*				
POM	1.20E-03	2.87E-04	1.26E-03				
Pyrene	4.25E-06	1.02E-06	4.45E-06				
Antimony	*5.25E-03*	*1.25E-03*	*5.50E-03*	*50*	*6.27E-04*	*2.75E-03*	*5.5*
Arsenic	1.32E-03	3.15E-04	1.38E-03	50	1.58E-04	6.91E-04	1.4
Barium	2.57E-03	6.14E-04	2.69E-03	50	3.07E-04	1.35E-03	2.7
Beryllium	2.78E-05	6.64E-06	2.91E-05	50	3.32E-06	1.46E-05	0.0
Cadmium	3.98E-04	9.51E-05	4.17E-04	50	4.76E-05	2.08E-04	0.4
Chloride	3.47E-01	8.29E-02	3.63E-01	75	2.07E-02	9.08E-02	182
Chromium	8.45E-04	2.02E-04	8.85E-04	50	1.01E-04	4.42E-04	0.9
Chromium VI	2.48E-04	5.93E-05	2.60E-04	50	2.96E-05	1.30E-04	0.3
Cobalt	6.02E-03	1.44E-03	6.30E-03	50	7.19E-04	3.15E-03	6.3
Copper	1.76E-03	4.21E-04	1.84E-03	50	2.10E-04	9.21E-04	1.8
Fluoride	3.73E-02	8.91E-03	3.90E-02	50	4.46E-03	1.95E-02	39.0
Lead	*1.51E-03*	*3.61E-04*	*1.58E-03*	*50*	1.80E-04	7.90E-04	1.6
Manganese	3.00E-03	7.17E-04	3.14E-03	50	3.59E-04	1.57E-03	3.1
Mercury	1.13E-04	2.70E-05	1.18E-04				
Molybdenum	7.87E-04	1.88E-04	8.24E-04	50	9.40E-05	4.12E-04	0.8
Nickel	8.45E-02	2.02E-02	8.85E-02	50	1.01E-02	4.42E-02	88
Phosphorous	9.46E-03	2.26E-03	9.90E-03	50	1.13E-03	4.95E-03	9.9
Selenium	6.83E-04	1.63E-04	7.15E-04	50	8.16E-05	3.57E-04	0.7
Vanadium	3.18E-02	7.60E-03	3.33E-02	50	3.80E-03	1.66E-02	33.3
Zinc	2.91E-02	6.95E-03	3.05E-02	50	3.48E-03	1.52E-02	30.5
Nitrous Oxide	5.30E-01	1.27E-01	5.55E-01				

Annual Hours = Annual Fuel Limit / Firing Rate = 8760 (no limit gal/yr)/(239 gal/hr) = 8760 hr
a) AP-42 Emission Factors for #6 fuel oil combustion less than 100 MMBtu/hr, Section 1.3
b) Assume total organic compounds is equivalent VOC
c) *Compounds which make up PAH*
d) Polyaromatic Hydrocarbons

Emission Estimates: BAF Blackfoot, Boiler 1 (formerly Boiler 8), No. 2 Fuel Oil

DEQ Reviewer, Date: Ken Hanna, March 22, 2005
#2 Fuel Oil Combustion: < 100 MMBtu/hr
Rated Input Capacity = 5.70E+07 Btu/hr
Actual Input Capacity = 5.46E+07 @ 140,000 Btu/gal and 7.21 lb/gal
Fuel usage rate = 390 gal/hr
Sulfur Content = 0.5 % by weight
Annual hours of operation= 8760

[redacted]							
SO_2	142*S[e]	27.7	121	75	6.92E+00	3.03E+01	
SO_3	2*S[e]	0.390	1.71				
NO_x	20	7.8	34.2				
CO	5	1.95	8.54				
PM Total	3.3	1.29	5.64	50	6.44E-01	2.82E+00	
PM-10	1.65	0.64	2.82	50	3.22E-01	1.41E+00	
VOC[b]	0.2	0.078	0.34				
Benzene		0.00E+00	0.00E+00				
Ethylbenzene		0.00E+00	0.00E+00				
Formaldehyde	4.80E-02	1.87E-02	8.20E-02				
Naphthalene		0.00E+00	0.00E+00				
1,1,1-Trichloroethane		0.00E+00	0.00E+00				
Toluene		0.00E+00	0.00E+00				
o-Xylene		0.00E+00	0.00E+00				
Acenaphthene		0.00E+00	0.00E+00				
Acenaphthylene		0.00E+00	0.00E+00				
Anthracene		0.00E+00	0.00E+00				
Benz(a)anthracene[c]		0.00E+00	0.00E+00				
Benzo(b,k)fluoranthene		0.00E+00	0.00E+00				
Benzo(g,h,l)perylene		0.00E+00	0.00E+00				
Chrysene[c]		0.00E+00	0.00E+00				
Dibenzo(a,h)anthracene[c]		0.00E+00	0.00E+00				
Fluoranthene		0.00E+00	0.00E+00				
Fluorene		0.00E+00	0.00E+00				
Indo (1,2,3-cd)pyrene[c]		0.00E+00	0.00E+00				
PAH[d]	0.00E+00	0.00E+00	0.00E+00				
Phenanthrene	0.00E+00	0.00E+00	0.00E+00				
POM	3.30E-03	1.29E-03	5.64E-03				
Pyrene		0.00E+00	0.00E+00				
Antimony		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Arsenic	6.00E-04	2.34E-04	1.02E-03	50	1.17E-04	5.12E-04	1.0
Barium		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Beryllium	4.00E-04	1.56E-04	6.83E-04	50	7.80E-05	3.42E-04	0.7
Cadmium	4.00E-04	1.56E-04	6.83E-04	50	7.80E-05	3.42E-04	0.7
Chloride		0.00E+00	0.00E+00	75	0.00E+00	0.00E+00	0
Chromium	4.00E-04	1.56E-04	6.83E-04	50	7.80E-05	3.42E-04	0.7
Chromium VI		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Cobalt		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Copper	8.00E-04	3.12E-04	1.37E-03	50	1.56E-04	6.83E-04	1.4
Fluoride		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Lead	1.30E-03	5.07E-04	2.22E-03	50	2.54E-04	1.11E-03	2.2
Manganese	8.00E-04	3.12E-04	1.37E-03	50	1.56E-04	6.83E-04	1.4
Mercury	4.00E-04	1.56E-04	6.83E-04				
Molybdenum		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Nickel	4.00E-04	1.56E-04	6.83E-04	50	7.80E-05	3.42E-04	1
Phosphorous		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Selenium	2.10E-03	8.19E-04	3.59E-03	50	4.10E-04	1.79E-03	3.6
Vanadium		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Zinc	6.00E-04	2.34E-04	1.02E-03	50	1.17E-04	5.12E-04	1.0
Nitrous Oxide	2.60E-01	1.01E-01	4.44E-01				

Annual Hours = Annual Fuel Limit / Firing Rate = (no limit gal/yr)/(390 gal/hr) = no limit = 8760 hr
a) AP-42 Emission Factors for #2 fuel oil combustion less than 100 MMBtu/hr, Section 1.3, or manufacturer data
b) Assume nonmethane total organic compounds (NMTOC) is equivalent VOC
c) Compounds which make up PAH
d) Polyaromatic Hydrocarbons
e) S = percentage of sulfur in fuel by weight (e.g., 1.5% is expressed as 1.5)

Emission Estimates: BAF Blackfoot, Boiler 1 (formerly Boiler 8), Natural Gas

DEQ Reviewer, Date:	Ken Hanna, March 22, 2005	
Natural Gas Combustion:	< 100 MMBtu/hr	
Rated Input Capacity =	5.70E+07	Btu/hr
Actual Input Capacity =	5.52E+07	Btu/hr
Heat Content of Natural Gas:	1020	Btu/ft^3
Annual Hours of Operation:	8760	hr/yr

NOx	100	5.41E+00
CO	84	4.55E+00
PM	7.6	4.11E-01
SO2	2.4	1.30E-01
VOC	5.5	2.98E-01
2-Methylnaphthalene	2.45E-05	1.33E-06
3-Methylchloranthrene	1.80E-06	9.74E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	8.66E-07
Acenaphthene	1.80E-06	9.74E-08
Acenaphthylene	1.80E-06	9.74E-08
Anthracene	2.40E-06	1.30E-07
Benz(a)anthracene (1)	1.80E-06	9.74E-08
Benzene	2.10E-03	1.14E-04
Benz(a)pyrene (1)	1.20E-06	6.49E-08
Benzo(b)fluoranthene (1)	1.80E-06	9.74E-08
Benzo(g,h,i)perylene	1.20E-06	6.49E-08
Benzo(k)fluoranthene (1)	1.80E-06	9.74E-08
Butane	2.10E+00	1.14E-01
Chrysene (1)	1.80E-06	9.74E-08
Dibenzo(a,h)anthracene (1)	1.20E-06	6.49E-08
Dichlorobenzene	1.20E-03	6.49E-05
Ethane	3.10E+00	1.68E-01
Fluoranthene	3.00E-06	1.62E-07
Fluorene	2.80E-06	1.52E-07
Formaldehyde	7.50E-02	4.06E-03
Hexane	1.80E+00	9.74E-02
Indeno(1,2,3-cd)pyrene (1)	1.80E-06	9.74E-08
Naphthalene	6.10E-04	3.30E-05
PAH (2)	1.14E-05	6.17E-07
Pentane	2.60E+00	1.41E-01
Phenanathrene	1.70E-05	9.20E-07
POM	8.82E-05	4.77E-06
Propane	1.60E+00	8.66E-02
Pyrene	5.00E-06	2.71E-07
Toluene	3.40E-03	1.84E-04
Arsenic	2.00E-04	1.08E-05
Barium	4.40E-03	2.38E-04
Beryllium	1.20E-05	6.49E-07
Cadmium	1.10E-03	5.95E-05
Chromium	1.40E-03	7.58E-05
Cobalt	8.40E-05	4.55E-06
Copper	8.50E-04	4.60E-05
Manganese	3.80E-04	2.06E-05
Mercury	2.60E-04	1.41E-05
Molybdenum	1.10E-03	5.95E-05
Nickel	2.10E-03	1.14E-04
Selenium	2.40E-05	1.30E-06
Vanadium	2.30E-03	1.24E-04
Zinc	2.90E-02	1.57E-03
Nitrous Oxide	2.20E+00	1.19E-01

Emission Factors are from AP-42 Section 1.4, 7/98 (< 100 MMBtu/hr)
(1) Compounds which make up PAH
(2) Sum of emission factors which make up PAH

Emission Estimates: BAF Blackfoot, Boiler 2 (formerly Boiler 6), No. 6 Fuel Oil

DEQ Reviewer, Date:	Ken Hanna, April 28, 2005	
#6 Fuel Oil Combustion < 100 MMBtu/hr		
Rated Input Capcity:	7.54E+07	Btu/hr
Actual Heat Input Rate:	6.03E+07	Btu/hr
Fuel usage rate:	402	gal/hr
Sulfur Content, by weight	1.75	% by weight
Annual hours of operation:	8760	hr/yr

[redacted]							
SO_2	157*S[a]	110.4	484	75	2.76E+01	1.21E+02	
SO_3	2*S[a]	1.407	6.16				
NO_x	96.64	38.8	170.2				
CO	13.2	5.31	23.24				
PM Total	20.8	8.36	36.62	50	4.18E+00	1.83E+01	
PM-10	17.9	7.20	31.52	50	3.60E+00	1.58E+01	
VOC[b]	0.28	0.113	0.49				
Benzene	2.14E-04	8.60E-05	3.77E-04				
Ethylbenzene	6.36E-05	2.56E-05	1.12E-04				
Formaldehyde	4.25E-02	1.71E-02	7.48E-02				
Naphthalene	1.13E-03	4.54E-04	1.99E-03				
1,1,1-Trichloroethane	2.36E-04	9.49E-05	4.16E-04				
Toluene	6.20E-03	2.49E-03	1.09E-02				
o-Xylene	1.09E-04	4.38E-05	1.92E-04				
Acenaphthene	2.11E-05	8.48E-06	3.72E-05				
Acenaphthylene	2.53E-07	1.02E-07	4.45E-07				
Anthracene	1.22E-06	4.90E-07	2.15E-06				
Benz(a)anthracene[c]	4.01E-06	1.61E-06	7.06E-06				
Benzo(b,k)fluoranthene	1.48E-06	5.95E-07	2.61E-06				
Benzo(g,h,i)perylene	2.26E-06	9.09E-07	3.98E-06				
Chrysene[c]	2.38E-06	9.57E-07	4.19E-06				
Dibenzo(a,h)anthracene[c]	1.67E-06	6.71E-07	2.94E-06				
Fluoranthene	4.84E-06	1.95E-06	8.52E-06				
Fluorene	4.47E-06	1.80E-06	7.87E-06				
Indo (1,2,3-cd)pyrene[c]	2.14E-06	8.60E-07	3.77E-06				
PAH[d]	1.02E-05	4.10E-06	1.80E-05				
Phenanthrene	1.05E-05	4.22E-06	1.85E-05				
POM	1.20E-03	4.82E-04	2.11E-03				
Pyrene	4.25E-06	1.71E-06	7.48E-06				
Antimony	5.25E-03	2.11E-03	9.24E-03	50	1.06E-03	4.62E-03	9.2
Arsenic	1.32E-03	5.31E-04	2.32E-03	50	2.65E-04	1.16E-03	2.3
Barium	2.57E-03	1.03E-03	4.53E-03	50	5.17E-04	2.26E-03	4.5
Beryllium	2.78E-05	1.12E-05	4.89E-05	50	5.59E-06	2.45E-05	0.0
Cadmium	3.98E-04	1.60E-04	7.01E-04	50	8.00E-05	3.50E-04	0.7
Chloride	3.47E-01	1.39E-01	6.11E-01	75	3.49E-02	1.53E-01	305
Chromium	8.45E-04	3.40E-04	1.49E-03	50	1.70E-04	7.44E-04	1.5
Chromium VI	2.48E-04	9.97E-05	4.37E-04	50	4.98E-05	2.18E-04	0.4
Cobalt	6.02E-03	2.42E-03	1.06E-02	50	1.21E-03	5.30E-03	10.6
Copper	1.76E-03	7.08E-04	3.10E-03	50	3.54E-04	1.55E-03	3.1
Fluoride	3.73E-02	1.50E-02	6.57E-02	50	7.50E-03	3.28E-02	65.7
Lead	1.51E-03	6.07E-04	2.66E-03	50	3.04E-04	1.33E-03	2.7
Manganese	3.00E-03	1.21E-03	5.28E-03	50	6.03E-04	2.64E-03	5.3
Mercury	1.13E-04	4.54E-05	1.99E-04				
Molybdenum	7.87E-04	3.16E-04	1.39E-03	50	1.58E-04	6.93E-04	1.4
Nickel	8.45E-02	3.40E-02	1.49E-01	50	1.70E-02	7.44E-02	149
Phosphorous	9.46E-03	3.80E-03	1.67E-02	50	1.90E-03	8.33E-03	16.7
Selenium	6.83E-04	2.75E-04	1.20E-03	50	1.37E-04	6.01E-04	1.2
Vanadium	3.18E-02	1.28E-02	5.60E-02	50	6.39E-03	2.80E-02	56.0
Zinc	2.91E-02	1.17E-02	5.12E-02	50	5.85E-03	2.56E-02	51.2
Nitrous Oxide	5.30E-01	2.13E-01	9.33E-01				

Annual Hours = Annual Fuel Limit / Firing Rate = (no limit gal/yr)/(410 gal/hr) = no limit = 8760 hr

a) AP-42 Emission Factors for #6 fuel oil combustion less than 100 MMBtu/hr, Section 1.3

b) Assume total organic compounds is equivalent VOC

c) Compounds which make up PAH

d) *Polyaromatic Hydrocarbons*

Emission Estimates: BAF Blackfoot, Boiler 2 (formerly Boiler 6), No. 2 Fuel Oil

DEQ Reviewer, Date:	Ken Hanna, March 23, 2005	
#2 Fuel Oil Combustion:	< 100 MMBtu/hr	
Rated Input Capacity =	7.54E+07	Btu/hr
Actual Heat Input Rate =	7.18E+07	@ 140,000 Btu/gal and 7.21 lb/gal
Fuel usage rate =	513	gal/hr
Sulfur Content =	0.5	% by weight
Annual hours of operation=	8760	

SO_2	142*S[e]	36.4	160	75	9.11E+00	3.99E+01	
SO_3	2*S[e]	0.513	2.25				
NO_x	10	5.1	22.5				
CO	5	2.57	11.23				
PM Total	3.3	1.69	7.41	50	8.46E-01	3.71E+00	
PM-10	1.65	0.85	3.71	50	4.23E-01	1.85E+00	
VOC[b]	0.2	0.103	0.45				
Benzene		0.00E+00	0.00E+00				
Ethylbenzene		0.00E+00	0.00E+00				
Formaldehyde	4.80E-02	2.46E-02	1.08E-01				
Naphthalene		0.00E+00	0.00E+00				
1,1,1-Trichloroethane		0.00E+00	0.00E+00				
Toluene		0.00E+00	0.00E+00				
o-Xylene		0.00E+00	0.00E+00				
Acenaphthene		0.00E+00	0.00E+00				
Acenaphthylene		0.00E+00	0.00E+00				
Anthracene		0.00E+00	0.00E+00				
Benz(a)anthracene[c]		0.00E+00	0.00E+00				
Benzo(b,k)fluoranthene		0.00E+00	0.00E+00				
Benzo(g,h,i)perylene		0.00E+00	0.00E+00				
Chrysene[c]		0.00E+00	0.00E+00				
Dibenzo(a,h)anthracene[c]		0.00E+00	0.00E+00				
Fluoranthene		0.00E+00	0.00E+00				
Fluorene		0.00E+00	0.00E+00				
Indo (1,2,3-cd)pyrene[c]		0.00E+00	0.00E+00				
PAH[d]	0.00E+00	0.00E+00	0.00E+00				
Phenanthrene	0.00E+00	0.00E+00	0.00E+00				
POM	3.30E-03	1.69E-03	7.41E-03				
Pyrene		0.00E+00	0.00E+00				
Antimony		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Arsenic	6.00E-04	3.08E-04	1.35E-03	50	1.54E-04	6.74E-04	1.3
Barium		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Beryllium	4.00E-04	2.05E-04	8.99E-04	50	1.03E-04	4.49E-04	0.9
Cadmium	4.00E-04	2.05E-04	8.99E-04	50	1.03E-04	4.49E-04	0.9
Chloride		0.00E+00	0.00E+00	75	0.00E+00	0.00E+00	0
Chromium	4.00E-04	2.05E-04	8.99E-04	50	1.03E-04	4.49E-04	0.9
Chromium VI		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Cobalt		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Copper	8.00E-04	4.10E-04	1.80E-03	50	2.05E-04	8.99E-04	1.8
Fluoride		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Lead	1.30E-03	6.67E-04	2.92E-03	50	3.33E-04	1.46E-03	2.9
Manganese	8.00E-04	4.10E-04	1.80E-03	50	2.05E-04	8.99E-04	1.8
Mercury	4.00E-04	2.05E-04	8.99E-04				
Molybdenum		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Nickel	4.00E-04	2.05E-04	8.99E-04	50	1.03E-04	4.49E-04	1
Phosphorous		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Selenium	2.10E-03	1.08E-03	4.72E-03	50	5.39E-04	2.36E-03	4.7
Vanadium		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Zinc	6.00E-04	3.08E-04	1.35E-03	50	1.54E-04	6.74E-04	1.3
Nitrous Oxide	2.60E-01	1.33E-01	5.84E-01				

Annual Hours = Annual Fuel Limit / Firing Rate = (no limit gal/yr)/(513 gal/hr) = no limit = 8760 hr

a) AP-42 Emission Factors for #2 fuel oil combustion less than 100 MMBtu/hr, Section 1.3, or manufacturer data

b) Assume nonmethane total organic compounds (NMTOC) is equivalent VOC

c) Compounds which make up PAH

d) Polyaromatic Hydrocarbons

e) S = sulfur content in fuel by weight expressed as a percentage (e.g., 0.5% is expressed as 0.5)

Emission Estimates: BAF Blackfoot, Boiler 2 (formerly Boiler 6), Natural Gas

DEQ Reviewer, Date:	Ken Hanna, March 23, 2005
Natural Gas Combustion:	< 100 MMBtu/hr
Rated Input Capacity:	7.54E+07 Btu/hr
Actual Heat Input Rate:	7.35E+07 Btu/hr
Heat Content of Natural Gas:	1020 Btu/ft^3
Annual Hours of Operation:	8760 hr/yr

NOx	50	3.60E+00
CO	84	6.05E+00
PM	7.6	5.48E-01
SO2	2.4	1.73E-01
VOC	5.5	3.96E-01
2-Methylnaphthalene	2.45E-05	1.77E-06
3-Methylchloranthrene	1.80E-06	1.30E-07
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.15E-06
Acenaphthene	1.80E-06	1.30E-07
Acenaphthylene	1.80E-06	1.30E-07
Anthracene	2.40E-06	1.73E-07
Benz(a)anthracene (1)	1.80E-06	1.30E-07
Benzene	2.10E-03	1.51E-04
Benz(a)pyrene (1)	1.20E-06	8.65E-08
Benzo(b)fluoranthene (1)	1.80E-06	1.30E-07
Benzo(g,h,i)perylene	1.20E-06	8.65E-08
Benzo(k)fluoranthene (1)	1.80E-06	1.30E-07
Butane	2.10E+00	1.51E-01
Chrysene (1)	1.80E-06	1.30E-07
Dibenzo(a,h)anthracene (1)	1.20E-06	8.65E-08
Dichlorobenzene	1.20E-03	8.65E-05
Ethane	3.10E+00	2.23E-01
Fluoranthene	3.00E-06	2.16E-07
Fluorene	2.80E-06	2.02E-07
Formaldehyde	7.50E-02	5.40E-03
Hexane	1.80E+00	1.30E-01
Indeno(1,2,3-cd)pyrene (1)	1.80E-06	1.30E-07
Naphthalene	6.10E-04	4.40E-05
PAH (2)	1.14E-05	8.21E-07
Pentane	2.60E+00	1.87E-01
Phenanathrene	1.70E-05	1.23E-06
POM	8.82E-05	6.36E-06
Propane	1.60E+00	1.15E-01
Pyrene	5.00E-06	3.60E-07
Toluene	3.40E-03	2.45E-04
Arsenic	2.00E-04	1.44E-05
Barium	4.40E-03	3.17E-04
Beryllium	1.20E-05	8.65E-07
Cadmium	1.10E-03	7.93E-05
Chromium	1.40E-03	1.01E-04
Cobalt	8.40E-05	6.05E-06
Copper	8.50E-04	6.13E-05
Manganese	3.80E-04	2.74E-05
Mercury	2.60E-04	1.87E-05
Molybdenum	1.10E-03	7.93E-05
Nickel	2.10E-03	1.51E-04
Selenium	2.40E-05	1.73E-06
Vanadium	2.30E-03	1.66E-04
Zinc	2.90E-02	2.09E-03
Nitrous Oxide	2.20E+00	1.59E-01

Emission Factors are from AP-42 Section 1.4, 7/98 (< 100 MMBtu/hr)
(1) Compounds which make up PAH
(2) Sum of emission factors which make up PAH

Emission Estimates: BAF Blackfoot, Boiler 3 (formerly Boiler 7), No. 2 Fuel Oil

DEQ Reviewer, Date: Ken Hanna, March 23, 2005
#2 Fuel Oil Combustion: < 100 MMBtu/hr
Rated Input Capacity = 3.90E+07 Btu/hr
Actual Heat Input Rate = 3.82E+07 @ 140,000 Btu/gal and 7.21 lb/gal
Fuel usage rate = 273 gal/hr
Sulfur Content = 0.5 % by weight
Annual hours of operation= 8760

[redacted]

SO_2	142*S[e]	19.4	85	75	4.85E+00	2.12E+01	
SO_3	2*S[e]	0.273	1.20				
NO_x	10	2.7	12.0				
CO	5	1.37	5.98				
PM Total	3.3	0.90	3.95	50	4.50E-01	1.97E+00	
PM-10	1.65	0.45	1.97	50	2.25E-01	9.86E-01	
VOC[b]	0.2	0.055	0.24				
Benzene		0.00E+00	0.00E+00				
Ethylbenzene		0.00E+00	0.00E+00				
Formaldehyde	4.80E-02	1.31E-02	5.74E-02				
Naphthalene		0.00E+00	0.00E+00				
1,1,1-Trichloroethane		0.00E+00	0.00E+00				
Toluene		0.00E+00	0.00E+00				
o-Xylene		0.00E+00	0.00E+00				
Acenaphthene		0.00E+00	0.00E+00				
Acenaphthylene		0.00E+00	0.00E+00				
Anthracene		0.00E+00	0.00E+00				
Benz(a)anthracene[c]		0.00E+00	0.00E+00				
Benzo(b,k)fluoranthene		0.00E+00	0.00E+00				
Benzo(g,h,l)perylene		0.00E+00	0.00E+00				
Chrysene[c]		0.00E+00	0.00E+00				
Dibenzo(a,h)anthracene[c]		0.00E+00	0.00E+00				
Fluoranthene		0.00E+00	0.00E+00				
Fluorene		0.00E+00	0.00E+00				
Indo (1,2,3-cd)pyrene[c]		0.00E+00	0.00E+00				
PAH[d]	0.00E+00	0.00E+00	0.00E+00				
Phenanthrene	0.00E+00	0.00E+00	0.00E+00				
POM	3.30E-03	9.01E-04	3.95E-03				
Pyrene		0.00E+00	0.00E+00				
Antimony		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Arsenic	6.00E-04	1.64E-04	7.17E-04	50	8.19E-05	3.59E-04	0.7
Barium		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Beryllium	4.00E-04	1.09E-04	4.78E-04	50	5.46E-05	2.39E-04	0.5
Cadmium	4.00E-04	1.09E-04	4.78E-04	50	5.46E-05	2.39E-04	0.5
Chloride		0.00E+00	0.00E+00	75	0.00E+00	0.00E+00	0
Chromium	4.00E-04	1.09E-04	4.78E-04	50	5.46E-05	2.39E-04	0.5
Chromium VI		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Cobalt		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Copper	8.00E-04	2.18E-04	9.57E-04	50	1.09E-04	4.78E-04	1.0
Fluoride		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Lead	1.30E-03	3.55E-04	1.55E-03	50	1.77E-04	7.77E-04	1.6
Manganese	8.00E-04	2.18E-04	9.57E-04	50	1.09E-04	4.78E-04	1.0
Mercury	4.00E-04	1.09E-04	4.78E-04				
Molybdenum		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Nickel	4.00E-04	1.09E-04	4.78E-04	50	5.46E-05	2.39E-04	0
Phosphorous		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Selenium	2.10E-03	5.73E-04	2.51E-03	50	2.87E-04	1.26E-03	2.5
Vanadium		0.00E+00	0.00E+00	50	0.00E+00	0.00E+00	0.0
Zinc	6.00E-04	1.64E-04	7.17E-04	50	8.19E-05	3.59E-04	0.7
Nitrous Oxide	2.60E-01	7.10E-02	3.11E-01				

Annual Hours = Annual Fuel Limit / Firing Rate = (no limit gal/yr)/(273 gal/hr) = no limit = 8760 hr

a) AP-42 Emission Factors for #2 fuel oil combustion less than 100 MMBtu/hr, Section 1.3, or manufacturer data
b) Assume nonmethane total organic compounds (NMTOC) is equivalent VOC
c) Compounds which make up PAH
d) Polyaromatic Hydrocarbons
e) S = sulfur content in fuel by weight expressed as a percentage (e.g., 0.5% is expressed as 0.5)

Emission Estimates: BAF Blackfoot, Boiler 3 (formerly Boiler 7), Natural Gas

DEQ Reviewer, Date:	Ken Hanna, March 23, 2005	
Natural Gas Combustion:	< 100 MMBtu/hr	
Rated Input Capacity:	3.90E+07	Btu/hr
Actual Heat Input Rate:	3.90E+07	Btu/hr
Heat Content of Natural Gas:	1020	Btu/ft^3
Annual Hours of Operation:	8760	hr/yr

[redacted]		
NOx	100	3.82E+00
CO	84	3.21E+00
PM	7.6	2.91E-01
SO2	2.4	9.18E-02
VOC	5.5	2.10E-01
2-Methylnaphthalene	2.45E-05	9.37E-07
3-Methylchloranthrene	1.80E-06	6.88E-08
7,12-Dimethylbenz(a)anthracene	1.60E-05	6.12E-07
Acenaphthene	1.80E-06	6.88E-08
Acenaphthylene	1.80E-06	6.88E-08
Anthracene	2.40E-06	9.18E-08
Benz(a)anthracene (1)	1.80E-06	6.88E-08
Benzene	2.10E-03	8.03E-05
Benz(a)pyrene (1)	1.20E-06	4.59E-08
Benzo(b)fluoranthene (1)	1.80E-06	6.88E-08
Benzo(g,h,l)perylene	1.20E-06	4.59E-08
Benzo(k)fluoranthene (1)	1.80E-06	6.88E-08
Butane	2.10E+00	8.03E-02
Chrysene (1)	1.80E-06	6.88E-08
Dibenzo(a,h)anthracene (1)	1.20E-06	4.59E-08
Dichlorobenzene	1.20E-03	4.59E-05
Ethane	3.10E+00	1.19E-01
Fluoranthene	3.00E-06	1.15E-07
Fluorene	2.80E-06	1.07E-07
Formaldehyde	7.50E-02	2.87E-03
Hexane	1.80E+00	6.88E-02
Indeno(1,2,3-cd)pyrene (1)	1.80E-06	6.88E-08
Naphthalene	6.10E-04	2.33E-05
PAH (2)	1.14E-05	4.36E-07
Pentane	2.60E+00	9.94E-02
Phenanathrene	1.70E-05	6.50E-07
POM	8.82E-05	3.37E-06
Propane	1.60E+00	6.12E-02
Pyrene	5.00E-06	1.91E-07
Toluene	3.40E-03	1.30E-04
Arsenic	2.00E-04	7.65E-06
Barium	4.40E-03	1.68E-04
Beryllium	1.20E-05	4.59E-07
Cadmium	1.10E-03	4.21E-05
Chromium	1.40E-03	5.35E-05
Cobalt	8.40E-05	3.21E-06
Copper	8.50E-04	3.25E-05
Manganese	3.80E-04	1.45E-05
Mercury	2.60E-04	9.94E-06
Molybdenum	1.10E-03	4.21E-05
Nickel	2.10E-03	8.03E-05
Selenium	2.40E-05	9.18E-07
Vanadium	2.30E-03	8.79E-05
Zinc	2.90E-02	1.11E-03
Nitrous Oxide	2.20E+00	8.41E-02

Emission Factors are from AP-42 Section 1.4, 7/98 (< 100 MMBtu/hr)
(1) Compounds which make up PAH
(2) Sum of emission factors which make up PAH

Date:	3/7/2005
Facility:	BAF Blackfoot
Facility ID:	011-00012
Permit No.:	P-050301
Source:	Boiler No. 1 (formerly No. 8)
Manufacturer:	Murray
Model No.:	
Rated Heat Input:	57 MMBtu/hr
Fuel:	No. 6 Oil

Combustion Evaluation

Fuel Input rate :	239	gal/hr
Fuel Density[1] :	8.21	lb/gal
Fuel high heating value =	150,000	Btu/gal
Firing rate being evaluated =	36	MMBtu/hr

Fuel Data (% by weight)
No. 6 Oil (1)

S	1.75
N_2	0.92
C	85.7
H_2	10.5
H_20	0
O_2	0.92

Fuel burned (lb/hr)	1962
Excess air (%)[2]	15
Stk temp (F)	300
Stack press (atm)	0.847
Elevation (ft)	4473
Stk exit height from ground level (ft)	100

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	1.07	4.03
N_2	0.00	0
C	140	527
H_2	51.1	192
O_2	-0.56	
	191.64	723.04

stioc. comb air = 968 lb.mole/hr
stoic. dry comb air = 864 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO_2	1.07	68.5
N_2	832	23300
CO_2	140	6160
H_2O(comb)	103	1854
O_2	28.7	920
H_2O(fuel)	0.00	0.00
dry	1002	
wet	1105	

	Flow[3]	IDAPA Flow[4]
Volume of flue gas (acfm)	12064	
Volume of flue gas (dscfm)	6341	
Volume of flue gas (dscfm@7%O_2)	8203	9645
Volume of flue gas (dscfm@15%O_2)	19140	22504
Volume of flue gas (dscfm@8%O_2)	8834	10386
Volume of flue gas (dscfm@3%O_2)	6380	7501
Volume of flue gas (dscfm@10%O_2)	10440	12275

1) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Fuel Oil Table 5-3
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Table 4-4, and engineering judgement.
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680 & T = 68 F

Date:	3/7/2005
Facility:	BAF Blackfoot
Facility ID:	011-00012
Permit No.:	P-050301
Source:	Boiler No. 1 (formerly No. 8)
Manufacturer:	Murray
Model No.:	
Rated Heat Input:	57 MMBtu/hr
Fuel:	No. 2 Oil

Combustion Evaluation

Fuel Input rate : 390 gal/hr

Fuel Density(1) : 7.21 lb/gal

Fuel high heating value = 141,000 Btu/gal

Firing rate being evaluated = 55 MMBtu/hr

Fuel Data (% by weight)
No. 2 Oil (1)

S	0.5
N_2	0.2
C	86.4
H_2	12.7
H_20	0
O_2	0.2

Fuel burned (lb/hr)	2812
Excess air (%)(2)	15
Stk temp (F)	300
Stack press (atm)	0.847
Elevation (ft)	4473
Stk exit height from ground level (ft)	100

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	0.44	1.65
N_2	0.00	0
C	202	761
H_2	88.6	333
O_2	-0.18	
	291.15	1095.93

stioc. comb air = 1477 lb.mole/hr

stoic. dry comb air = 1299 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO_2	0.44	28.1
N_2	1261	35295
CO_2	202	8900
H_2O(comb)	179	3214
O_2	43.7	1398
H_2O(fuel)	0.00	0.00
dry	1507	
wet	1685	

	Flow(3)	IDAPA Flow(4)
Volume of flue gas (acfm)	18402	
Volume of flue gas (dscfm)	9536	
Volume of flue gas (dscfm@7%O_2)	12327	14494
Volume of flue gas (dscfm@15%O_2)	28764	33820
Volume of flue gas (dscfm@8%O_2)	13276	15609
Volume of flue gas (dscfm@3%O_2)	9588	11273
Volume of flue gas (dscfm@10%O_2)	15689	18447

1) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Fuel Oil Table 5-3
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Table 4-4, and engineering judgement.
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680 & T = 68 F

Facility: BAF Blackfoot
Facility ID: 011-00012
Permit No.: P-050301
Source: Boiler No. 1 (formerly No. 8)
Make: Murray
Model No.:
Rated Input 57 MMBtu/hr
Fuel: Natural Gas

Combustion Evaluation

Heat Input rate	55.2	MMBtu/hr
Fuel Density(1) = 1 lb per	23.8	ft^3
Fuel high heating value =	1020	Btu/scf

Fuel Data (% by weight)
Natural Gas(2)

S	0.068
N_2	1.6879789
C	73.99
H_2	24.26
H_2O	0
O_2	0

Fuel burned (lb/hr)	2273.8507
Excess air (%)(5)	10
Stk temp (F)	300
Stack press (atm)	0.8462567
Elevation (ft)	4500
Stk exit height from ground level (ft)	100

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	0.05	0.18
N_2	0.00	0
C	140.07	526.94
H_2	136.88	514.94
O_2	0.00	
	277.00	1042.06

stioc. comb air = 1459.373512 lb.mole/hr
stoic. dry comb air = 1182.1846 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO_2	0.05	3.09
N_2	1147.64	32133.92
CO_2	140.07	6163.23
H_2O(comb)	275.82	4964.73
O_2	27.70	886.41
H_2O(fuel)	0.00	0.00
dry	1315.46	
wet	1591.28	

	Flow(3)	IDAPA Flow(4)
Volume of flue gas (acfm)	17392.0	
Volume of flue gas (dscfm)	8324.8	
Volume of flue gas (dscfm@7%O_2)	11222.0	13208.6
Volume of flue gas (dscfm@15%O_2)	26184.7	30820.0
Volume of flue gas (dscfm@8%O_2)	12085.2	14224.6
Volume of flue gas (dscfm@3%O_2)	8728.2	10273.3
Volume of flue gas (dscfm@10%O_2)	14282.6	16810.9

1) Data from EPA AP-42 Appendix A, A-7
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Natural Gas Table 5-1
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680
5) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, for natural gas combustion in register type burners, Table 4-4

Date:	3/7/2005
Facility:	BAF Blackfoot
Facility ID:	011-00012
Permit No.:	P-050301
Source:	Boiler No. 2 (formerly No. 6)
Manufacturer:	Johnson 509 Series
Model No.:	TF 1800
Rated Heat Input:	75.4 MMBtu/hr
Fuel:	No. 6 Oil

Combustion Evaluation

Fuel Input rate : 410 gal/hr
Fuel Density[1] : 8.21 lb/gal
Fuel high heating value = 150,000 Btu/gal
Firing rate being evaluated = 62 MMBtu/hr

Fuel Data (% by weight)
No. 6 Oil (1)

S	1.75
N_2	0.92
C	85.7
H_2	10.5
H_20	0
O_2	0.92

Fuel burned (lb/hr)	3366
Excess air (%)[2]	15
Stk temp (F)	300
Stack press (atm)	0.847
Elevation (ft)	4473
Stk exit height from ground level (ft)	100

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	1.84	6.91
N_2	0.00	0
C	240	904
H_2	87.7	330
O_2	-0.97	
	328.75	1240.35

stioc. comb air = 1660 lb.mole/hr
stoic. dry comb air = 1482 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO_2	1.84	117.6
N_2	1428	39970
CO_2	240	10568
H_2O(comb)	177	3181
O_2	49.3	1578
H_2O(fuel)	0.00	0.00
dry	1719	
wet	1896	

	Flow[3]	IDAPA Flow[4]
Volume of flue gas (acfm)	20696	
Volume of flue gas (dscfm)	10877	
Volume of flue gas (dscfm@7%O_2)	14072	16545
Volume of flue gas (dscfm@15%O_2)	32834	38605
Volume of flue gas (dscfm@8%O_2)	15154	17818
Volume of flue gas (dscfm@3%O_2)	10945	12868
Volume of flue gas (dscfm@10%O_2)	17909	21057

1) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Fuel Oil Table 5-3
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Table 4-4, and engineering judgement.
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680 & T = 68 F

Date:	3/7/2005
Facility:	BAF Blackfoot
Facility ID:	011-00012
Permit No.:	P-050301
Source:	Boiler No. 2 (formerly No. 6)
Manufacturer:	Johnson 509 Series
Model No.:	TF 1800
Rated Heat Input:	75.4 MMBtu/hr
Fuel:	No. 2 Oil

Combustion Evaluation

Fuel Input rate : 513 gal/hr

Fuel Density[1] = 7.21 lb/gal

Fuel high heating value = 141,000 Btu/gal

Firing rate being evaluated = 72 MMBtu/hr

Fuel Data (% by weight)

No. 2 Oil (1)

S	0.5
N_2	0.2
C	86.4
H_2	12.7
H_2O	0
O_2	0.2

Fuel burned (lb/hr)	3699
Excess air (%)[2]	15
Stk temp (F)	300
Stack press (atm)	0.847
Elevation (ft)	4473
Stk exit height from ground level (ft)	100

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	0.58	2.17
N_2	0.00	0
C	266	1001
H_2	116.6	438
O_2	-0.23	
	382.97	1441.57

stioc. comb air = 1943 lb.mole/hr

stoic. dry comb air = 1708 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO_2	0.58	36.9
N_2	1658	46426
CO_2	266	11707
H_2O(comb)	235	4228
O_2	57.4	1838
H_2O(fuel)	0.00	0.00
dry	1982	
wet	2217	

	Flow[3]	IDAPA Flow[4]
Volume of flue gas (acfm)	24205	
Volume of flue gas (dscfm)	12544	
Volume of flue gas (dscfm@7%O_2)	16215	19066
Volume of flue gas (dscfm@15%O_2)	37836	44486
Volume of flue gas (dscfm@8%O_2)	17463	20532
Volume of flue gas (dscfm@3%O_2)	12612	14829
Volume of flue gas (dscfm@10%O_2)	20638	24265

1) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Fuel Oil Table 5-3
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Table 4-4, and engineering judgement.
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680 & T = 68 F

Facility: BAF Blackfoot
Facility ID: 011-00012
Permit No.: P-050301
Source: Boiler No. 2 (formerly No. 6)
Make: Johnson 509 Series
Model No.: TF 1800
Rated Input 75.4 MMBtu/hr
Fuel: Natural Gas

Combustion Evaluation

Heat Input rate	73.5	MMBtu/hr
Fuel Density(1) = 1 lb per	23.8	ft^3
Fuel high heating value =	1020	Btu/scf

Fuel Data (% by weight)
Natural Gas(2)

S	0.068
N_2	1.6879789
C	73.99
H_2	24.26
H_2O	0
O_2	0

Fuel burned (lb/hr)	3027.6817
Excess air (%)(5)	10
Stk temp (F)	300
Stack press (atm)	0.8479278
Elevation (ft)	4500
Stk exit height from ground level (ft)	50

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	0.06	0.24
N_2	0.00	0
C	186.51	701.64
H_2	182.26	685.65
O_2	0.00	
	368.84	1387.53

Flue Products

	lb.mole	lb/hr
SO_2	0.06	4.11
N_2	1528.11	42787.01
CO_2	186.51	8206.48
H_2O(comb)	367.26	6610.64
O_2	36.88	1180.28
H_2O(fuel)	0.00	0.00
dry	1751.57	
wet	2118.82	

stioc. comb air = 1943.187557 lb.mole/hr
stoic. dry comb air = 1574.1045 lb.mole/hr

	Flow(3)	IDAPA Flow(4)
Volume of flue gas (acfm)	23112.1	
Volume of flue gas (dscfm)	11084.6	
Volume of flue gas (dscfm@7%O_2)	14942.3	17587.5
Volume of flue gas (dscfm@15%O_2)	34865.5	41037.6
Volume of flue gas (dscfm@8%O_2)	16091.8	18940.4
Volume of flue gas (dscfm@3%O_2)	11621.8	13679.2
Volume of flue gas (dscfm@10%O_2)	19017.5	22384.1

1) Data from EPA AP-42 Appendix A, A-7
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Natural Gas Table 5-1
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680
5) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, for natural gas combustion in register type burners, Table 4-4

Date:	3/7/2005
Facility:	BAF Blackfoot
Facility ID:	011-00012
Permit No.:	P-050301
Source:	Boiler No. 3 (formerly No. 7)
Manufacturer:	Springfield
Model No.:	52
Rated Heat Input:	39 MMBtu/hr
Fuel:	No. 2 Oil

Combustion Evaluation

Fuel Input rate :	273	gal/hr
Fuel Density(1) :	7.21	lb/gal
Fuel high heating value =	141,000	Btu/gal
Firing rate being evaluated =	38	MMBtu/hr

Fuel Data (% by weight)
No. 2 Oil (1)

S	0.5
N_2	0.2
C	86.4
H_2	12.7
H_2O	0
O_2	0.2

Fuel burned (lb/hr)	1968
Excess air (%)(2)	15
Stk temp (F)	475
Stack press (atm)	0.849
Elevation (ft)	4473
Stk exit height from ground level (ft)	44

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	0.31	1.15
N_2	0.00	0
C	142	533
H_2	62.0	233
O_2	-0.12	
	203.80	767.15

stioc. comb air = 1034 lb.mole/hr
stoic. dry comb air = 909 lb.mole/hr

Flue Products

	lb.mole	lb/hr
SO_2	0.31	19.6
N_2	882	24706
CO_2	142	6230
H_2O(comb)	125	2250
O_2	30.6	978
H_2O(fuel)	0.00	0.00
dry	1055	
wet	1180	

	Flow(3)	IDAPA Flow(4)
Volume of flue gas (acfm)	15812	
Volume of flue gas (dscfm)	6675	
Volume of flue gas (dscfm@7%O_2)	8629	10146
Volume of flue gas (dscfm@15%O_2)	20135	23674
Volume of flue gas (dscfm@8%O_2)	9293	10927
Volume of flue gas (dscfm@3%O_2)	6712	7891
Volume of flue gas (dscfm@10%O_2)	10983	12913

1) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Fuel Oil Table 5-3
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Table 4-4, and engineering judgement.
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680 & T = 68 F

Facility: BAF Blackfoot
Facility ID: 011-00012
Permit No.: P-050301
Source: Boiler No. 3 (formerly No. 7)
Make: Springfield
Model No.: 52
Rated Input 39 MMBtu/hr
Fuel: Natural Gas

Combustion Evaluation

Heat Input rate	38.9	MMBtu/hr
Fuel Density[1] = 1 lb per	23.8	ft^3
Fuel high heating value =	1020	Btu/scf

Fuel Data (% by weight)
Natural Gas(2)

S	0.068
N_2	1.6879789
C	73.99
H_2	24.26
H_2O	0
O_2	0

Fuel burned (lb/hr)	1602.4057
Excess air (%)[5]	10
Stk temp (F)	475
Stack press (atm)	0.8481283
Elevation (ft)	4500
Stk exit height from ground level (ft)	44

Combustion Air Required

	O_2 lb.mole	N_2 lb.mole
S	0.03	0.13
N_2	0.00	0
C	98.71	371.34
H_2	96.46	362.88
O_2	0.00	
	195.21	734.35

Flue Products

	lb.mole	lb/hr
SO_2	0.03	2.18
N_2	808.75	22645.10
CO_2	98.71	4343.29
H_2O(comb)	194.37	3498.69
O_2	19.52	624.66
H_2O(fuel)	0.00	0.00
dry	927.02	
wet	1121.39	

stioc. comb air = 1028.435319 lb.mole/hr
stoic. dry comb air = 833.0975 lb.mole/hr

	Flow[3]	IDAPA Flow[4]
Volume of flue gas (acfm)	15045.2	
Volume of flue gas (dscfm)	5866.6	
Volume of flue gas (dscfm@7%O_2)	7908.3	9308.2
Volume of flue gas (dscfm@15%O_2)	18452.6	21719.2
Volume of flue gas (dscfm@8%O_2)	8516.6	10024.2
Volume of flue gas (dscfm@3%O_2)	6150.9	7239.7
Volume of flue gas (dscfm@10%O_2)	10065.1	11846.8

1) Data from EPA AP-42 Appendix A, A-7
2) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, Natural Gas Table 5-1
3) Standard conditions based on a pressure of 1.0 atmospheres and 60 F °
4) Standard conditions corrected for altitude per IDAPA 58.01.01.680
5) Data from EPA, Combustion Evaluation in Air Pollution Control, Student Manual, March 1994, for natural gas combustion in register type burners, Table 4-4

Appendix C

Modeling Review

P-050301

MEMORANDUM

DATE: June 23, 2005

TO: Ken Hanna, Permitting Engineer – Air Program Division

FROM: Kevin Schilling, Modeling Coordinator – Stationary Sources, Air Program Division

PROJECT NUMBER: P-050301

SUBJECT: Modeling review for the Basic American Foods (BAF) Permit to Construct (PTC) application for boiler modifications at their Blackfoot, Idaho facility.

1.0 SUMMARY

Basic American Foods (BAF) submitted an application to modify their dehydrated food products and animal feed facility located near Blackfoot, Idaho. Air quality analyses involving atmospheric dispersion modeling of emissions associated with the proposed modification were submitted in support of a permit to construct (PTC) application to demonstrate that the modification of the stationary source would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02). Coal Creek Environmental Associates, LLC (Coal Creek), BAF's consultant, conducted the ambient air quality analyses.

A technical review of the submitted air quality analyses was conduced by DEQ. DEQ also conducted independent analyses to assess the potential for emissions from the modified source by itself, without considering emission reductions from existing operations, to cause an exceedance of ambient air quality standards. The submitted modeling analyses in combination with DEQ's staff analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data; 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that predicted pollutant concentrations from emissions associated with the proposed modification were below significant contribution levels (SCLs); or b) that predicted pollutant concentrations from facility-wide emissions, when appropriately combined with background concentrations, were below applicable air quality standards. Impacts of Toxic Air Pollutants (TAPs) were all below allowable increments of IDAPA 58.01.01.585 and 586. Table 1 presents key assumptions and results that should be considered in the development of the permit.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
Only two of the three Boilers will be operating simultaneously.	Modeling analyses considered several operational scenarios, each scenario involving the operation of only two boilers at any time. A permit limit should be established to make this assumption enforceable. The worst-case scenario was based on operation of two boilers firing 14,384 gal/day of #6 oil.
Emissions will be controlled by a scrubber when any oil is combusted in Boilers 1 and 2.	When burning any oil, the permit should require that emissions be routed through a scrubber to control sulfur dioxide (SO_2) and PM_{10}.

2.0 BACKGROUND INFORMATION

2.1 Proposed Modification

BAF requested renaming the boilers: Boiler 8 is now Boiler 1; Boiler 6 is now Boiler 2; Boiler 7 is now Boiler 3.

The proposed modification involves the following:

- Removal of limits on operating hours for Boilers 1 and 2.
- Boiler 2 modified to burn No. 6 fuel oil (allowable fuels will include natural gas, No. 2 oil, and No. 6 oil).
- Maximum sulfur content for No. 6 oil combusted in Boiler 1 and 2 will be 1.75% (current limit is 1.5%).
- Only two of the boilers (No. 1, 2, or 3) will operate at any one time.
- Burning any oil in boilers 1 and 2 will be limited such that SO_2 emissions do not exceed 45.3 lb/hr.
- When Boilers 1 and 2 are burning any oil, SO_2 and PM_{10} emissions will be controlled by a scrubber, and emissions will exit through the stack for Boiler 1. When Boiler 2 is burning natural gas, emissions will not be controlled by a scrubber and emissions will exhaust through the existing stack for Boiler 2.

2.2 Applicable Air Quality Impact Limits and Modeling Requirements

This section identifies applicable ambient air quality limits and analyses used to demonstrate compliance.

2.2.1 Area Classification

The BAF Blackfoot facility is located in Bingham County, designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), and particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}). There are no Class I areas within 10 kilometers of the facility.

2.2.2 Significant and Full Impact Analyses

If estimated maximum pollutant impacts to ambient air from the emissions sources of the proposed modification and associated emissions increases and decreases exceed the significant contribution levels (SCLs) of IDAPA 58.01.01.006.91, then a full impact analysis is typically necessary to demonstrate compliance with IDAPA 58.01.01.203.02. A full impact analysis for attainment area pollutants involves adding ambient impacts from facility-wide emissions to DEQ-approved background concentration values that are appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SCLs and specifies the modeled value that must be used for comparison to the NAAQS.

Table 2. APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Significant Contribution Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Value Used[d]
PM_{10}[e]	Annual	1.0	50[f]	Maximum 1st highest[g]
	24-hour	5.0	150[h]	Maximum 6th highest[i]
Carbon monoxide (CO)	8-hour	500	10,000[j]	Maximum 2nd highest[g]
	1-hour	2,000	40,000[j]	Maximum 2nd highest[g]
Sulfur Dioxide (SO_2)	Annual	1.0	80[f]	Maximum 1st highest[g]
	24-hour	5	365[j]	Maximum 2nd highest[g]
	3-hour	25	1,300[j]	Maximum 2nd highest[g]
Nitrogen Dioxide (NO_2)	Annual	1.0	100[f]	Maximum 1st highest[g]
Lead (Pb)	Quarterly	NA	1.5[h]	Maximum 1st highest[g]

a. IDAPA 58.01.01.006.91
b. Micrograms per cubic meter
c. IDAPA 58.01.01.577 for criteria pollutants
d. The maximum 1st highest modeled value is always used for significant impact analysis
e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
f. Never expected to be exceeded in any calendar year
g. Concentration at any modeled receptor
h. Never expected to be exceeded more than once in any calendar year
i. Concentration at any modeled receptor when using five years of meteorological data
j. Not to be exceeded more than once per year

2.2.3 Toxic Air Pollutant Impact Analysis

Toxic Air Pollutant (TAP) analysis requirements for PTCs are specified in IDAPA 58.01.01.210. If the uncontrolled emissions increase associated with a new source or modification exceeds screening emission levels (ELs) of IDAPA 58.01.01.585 or IDAPA 58.01.01.586, then air dispersion modeling must be conducted to evaluate whether TAP impacts are below applicable TAP increments. If modeled impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of IDAPA 58.01.01.585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of IDAPA 58.01.01.586, then compliance with TAP requirements has been demonstrated.

2.3 Background Concentrations

Background concentrations were revised for all areas of Idaho by DEQ in March 2003[1]. Background concentrations in areas where no monitoring data are available were based on monitoring data from areas with similar population density, meteorology, and emissions sources.

Background concentrations were previously provided to BAF by DEQ for use in their PTC application to burn No. 6 oil in Boiler 1 (received by DEQ on January 5, 2004). These concentrations were based on default values for rural/agricultural areas. DEQ staff were concerned that use of these background concentrations may not adequately account for impacts from Nonpareil Corporation (Facility-Wide Tier II Permit Application, January 2005), a neighboring facility immediately east of BAF. Because a full impact analysis was only necessary for NO_2, resolving concerns with background concentrations was not a substantial issue. DEQ used information obtained from Nonpareil to evaluate combined impacts (see Section 3.5). Table 3 lists default background concentrations for rural/agricultural areas in Idaho.

1 Hardy, Rick and Schilling, Kevin. *Background Concentrations for Use in New Source Review Dispersion Modeling*. Memorandum to Mary Anderson, DEQ, March 14, 2003.

Table 3. BACKGROUND CONCENTRATIONS

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)[a]
PM_{10}[b]	Annual	26
	24-Hour	73
Carbon monoxide (CO)	8-Hour	2,300
	1-Hour	3,600
Sulfur Dioxide (SO_2)	Annual	8
	24-Hour	26
	3-Hour	34
Nitrogen Dioxide (NO_2)	Annual	17
Lead (Pb)	Quarterly	0.03

[a] Micrograms per cubic meter

[b] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

3.0 MODELING IMPACT ASSESSMENT

3.1 Modeling Methodology

Table 4 provides a summary of the modeling parameters used for DEQ's verification analyses.

Table 4. MODELING PARAMETERS

Parameter	Description/Values	Documentation/Additional Description
Model	ISC-PRIME	Version 04269
Meteorological data	Pocatello surface data Boise upper air data	1987-1992
Terrain	Terrain considered	Elevation data from digital elevation model (DEM) files
Building downwash	PRIME algorithm	Building dimensions obtained from modeling files submitted
Receptor grid	Grid 1	25-meter spacing along boundary out to 100 meters
	Grid 2	100-meter spacing out to 1,000 meters
Facility location (UTM)[a]	Easting	388 kilometers
	Northing	4,784 kilometers

[a] Universal Transverse Mercator

3.1.1 Modeling protocol

A modeling protocol was submitted to DEQ on January 28, 2005. The protocol was submitted by Coal Creek. The protocol was approved by DEQ and modeling was conducted in accordance with procedures discussed in the protocol.

3.1.2 Model Selection

ISC-PRIME was used by Coal Creek to conduct the ambient air analyses. ISCST3 cannot be used in this instance because numerous ambient air receptor locations exist within building recirculation cavities, and ISCST3 does not calculate concentrations within recirculation cavities. ISC-PRIME incorporates the PRIME downwash algorithm, which is also used in AERMOD, the proposed replacement model for ISCST3. The PRIME algorithm is superior to the existing downwash algorithms within ISCST3 and is capable of estimating concentrations within building recirculation cavities.

3.1.3 Land Use Classification

The area within a 3-kilometer radius is predominantly rural. Therefore, rural dispersion coefficients were used rather than urban coefficients.

3.1.4 Meteorological Data

Coal Creek used meteorological input files generated from Pocatello surface data and Boise upper air data, as requested by DEQ. These data are the most representative available for the BAF Blackfoot facility.

PCRAMMET, the meteorological data preprocessor for ISCST-3, occasionally generates unrealistically low mixing heights as a result of interpolation algorithms used with the twice daily measured mixing heights. DEQ verification modeling was conducted using meteorological data corrected for low mixing heights. All mixing height values below 50 meters were replaced with a value of 50 meters.

3.1.5 Terrain Effects

The modeling analyses submitted by Coal Creek considered elevated terrain. Elevations of receptors, buildings, and emissions sources were calculated from United States Geological Survey (USGS) 7.5 minute Digital Elevation Model (DEM) files. Elevations were recalculated from DEM files for the DEQ verification analyses.

3.1.6 Facility Layout

DEQ verified proper identification of the facility boundary and buildings on the site by comparing the modeling input to a facility plot plan submitted with the application and aerial photographs of the area.

3.1.7 Building Downwash

Plume downwash effects caused by structures present at the facility were accounted for in the modeling analyses. The Building Profile Input Program for the PRIME downwash algorithm (BPIP-PRIME) was used to calculate direction-specific building dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and emissions release parameters.

3.1.8 Ambient Air Boundary

The facility fence line was used as the ambient air boundary. This satisfies the requirements of preventing public access, as described in the *Idaho Air Quality Modeling Guideline*.

3.1.9 Receptor Network

The receptor grids used by Coal Creek met the recommendations specified in the *Idaho Air Modeling Guideline*, and DEQ determined the receptor spacing used was sufficient to reasonably resolve the maximum modeled concentration.

3.1.10 Modeling Approach

The proposed project, as summarized in Section 2.1, involves changing allowable emission rates and reconfiguring how existing emissions are released. Current actual emissions were modeled as negative emissions in the significant impact analyses, and proposed future potential emissions were modeled as positive emissions. This approach provides a reasonable assessment of the impact of the proposed project on air quality.

The complexity of various operational configurations necessitates modeling of several operational scenarios. Table 5 lists the operational scenarios modeled.

Table 5. OPERATIONAL SCENARIOS INCLUDED IN MODELING ANALYSES

Operational Scenario	Description	Comments on Conservatism
#6 Oil -1	Boilers 1 and 2 operating at permitted allowable rate for No. 6 oil, Boiler 3 not operating. Short term and long term hourly emission rates are equal.	Highly expected; highly representative
#6 Oil - 3	Short term: Boiler 1 operating full on No. 6 oil and Boiler 2 not operating (reduced flow from stack for Boiler 1 and 2), Boiler 3 operating at permit allowable rate[a]. Long term: Operate as short term for 8,568 hr/yr (limit for Boiler 3 on No. 2 oil), then operate Boiler 2 on #6 Oil-1 for remaining 192 hrs.	Reasonably expected; highly representative
#2 Oil - 1	Boilers 1 and 2 operating at permitted allowable for No. 2 oil. Boiler 3 not operating. Short term and long term hourly emission rates are equal.	Reasonably expected; highly representative

[a] This scenario is somewhat different than what was modeled by Coal Creek. The short-term scenario of #6 Oil – 3 used by Coal Creek was identical to #6 Oil – 1.

3.2 *Emission Rates*

Emissions rates used in the dispersion modeling analyses submitted by the applicant were reviewed against those in the permit application, the engineering technical memorandum, and the proposed permit. The following approach was used for DEQ verification modeling:

- All modeled emissions rates were equal to or slightly greater than the facility's emissions calculated in the PTC application or the permitted allowable rate, whichever was larger.
- Modeling results were compared to *significant contribution* thresholds. More extensive review of modeling parameters selected was conducted when model results approached applicable thresholds.

3.2.1 Proposed Emission Limits

Table 6 lists DEQ proposed emission limits for Boiler 1 and Boiler 2. Boiler 3 is included in the table, but was not included in the significant impact modeling analyses since neither the boiler nor its method of operation would be affected by this permitting action.

Table 6. PROPOSED ALLOWABLE EMISSION LIMITS

Source	PM_{10}[a]		SO_2[b]		NO_x[c]		CO[d]	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Boiler 1	2.1		16.9		23.1		4.6	
Boiler 2	3.6		28.4		38.8		6.1	
Boiler 3	0.30		1.9		5.4		1.8	
Total[e]		17.9		142		193		

[a] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
[b] Sulfur dioxide
[c] Oxides of nitrogen
[d] Carbon Monoxide
[e] Combined emissions from the Boiler 1, 2, and 3

3.2.2 Emissions Compared to Modeling Thresholds

The *Idaho Air Quality Modeling Guideline* suggests modeling be conducted for any criteria pollutant increase that exceeds listed modeling thresholds. Representative existing pollutant emissions must be calculated before the pollutant increase can be determined. Existing emissions were based on the highest annual average steam demand over the last two years, assuming No. 6 oil is fired in Boiler 1, as allowed by the PTC issued in 2004. Actual annual emissions were not used because the emissions prior to the PTC issued in 2004 would not be representative of the current plant configuration. Representative existing emissions were calculated using the methodology summarized in Table 7.

Table 7. CALCULATION OF EXISTING EMISSIONS

Emission Source	Averaging Period	Method to Calculate Emissions	Emissions (lb/hr[a])
Boiler 1	Hourly	Max of either 1) 227 gal/hr No. 6 oil; or 2) 36.4 MMBtu/hr Nat. Gas	PM_{10} = 3.3; SO_2 = 56.8; CO = 1.3
	Annual	1.64 MMgal/yr No. 6 oil; 19,142 MMBtu/yr Nat. Gas	PM_{10} = 2.7; SO_2 = 46.8; NO_x = 10.6; Pb = 2.8E-4
Boiler 2	Hourly	49.0 MMBtu/hr Nat. Gas	PM_{10} = 0.14; SO_2 = 0.03; CO = 3.3
	Annual	249,791 MMBtu/yr Nat. Gas	PM_{10} = 0.079; SO_2 = 0.023; NO_x = 1.1; Pb = 1.4E-5
Total	Hourly	Combined Boiler 1 and Boiler 2	PM_{10} = 3.5; SO_2 = 56.8; CO = 4.6
	Annual	Combined Boiler 1 and Boiler 2	PM_{10} = 2.8; SO_2 = 46.8; NO_x = 11.7; Pb = 2.9E-4

[a] Pounds per hour

Table 8 shows a comparison of emission increases to modeling thresholds, above which modeling is required. Boiler 3 is not modified as part of this PTC application, so neither existing nor allowable emissions from this boiler were included in the modeling applicability determination.

Table 8. MODELING APPLICABILITY DETERMINATION (BOILER 1 AND 2)

Pollutant	Avg. Period	Current Emissions (lb/hr)	Future Allowable Emissions (lb/hr)	Emission Increase (lb/hr)	Modeling Threshold (lb/hr)	Modeling Required
PM_{10}[a]	24-hr	3.5	5.7	2.2	0.2	Yes
	Annual	2.8	5.7	2.9	0.2	Yes
SO_2[b]	≤24-hr	56.8	45.3	-11.5	0.2	No
	Annual	46.8	45.3	-1.5	0.2	No
CO[c]	<24-hr	4.63	10.7	6.1	14	No
NO_x[d]	annual	11.7	61.9	50.2	0.23	Yes
Pb[e]	Quart.	3.4E-4	5.6E-4	2.2E-4	0.14	No

[a] Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
[b] Sulfur dioxide
[c] Carbon Monoxide
[d] Oxides of nitrogen
[e] Lead

Because of the change in emission release parameters, DEQ also modeled the proposed project by itself, without modeling emissions from the current configuration as negative values.

3.2.3 Emission Rates for Modeled Scenarios

The proposed project involves fuel changes, control equipment additions, and changes in how emissions are released (location of release and changes in release parameters such as flow rate, temperature, stack height, and stack diameter). Table 9 provides a description of the emission sources used in the modeling analyses. Tables 10, 11, and 12 list emissions used in the various modeling scenarios. Table 13 summarizes NO_x emissions from the boilers for various operational scenarios for the full impact analyses. Facility-wide NO_x emissions from other sources at the facility are provided in Appendix A. Appendix A also includes NO_x emissions from the neighboring Nonpariel facility that were used for a combined impact analysis conducted by DEQ (see Section 3.5)

Table 9. EMISSION SOURCES USED IN THE MODELING ANALYSES

Emission Source Code	Description
BLR6_VRT	Boiler 2 firing natural gas under current conditions.
BLR6_GAS	Boiler 2 firing natural gas under future conditions where exhausts from Boiler 1 and 2 are not merged.
BLR7	Boiler 3.
B8GS_VRT	Boiler 1 firing natural gas under current conditions.
B8OL_VRT	Boiler 1 firing No. 6 oil under current conditions.
BLR6_8	Boiler 1 and 2 under future conditions where exhausts are merged.
BLR8_GAS	Boiler 1 firing natural gas where exhausts from Boiler 6 and 8 are not merged.

Table 10. CRITERIA POLLUTANT EMISSION RATES USED FOR MODELING OF SCENARIO #6 OIL – 1[a]

Emission Point	Rate Used for Modeling (lb/hr)[b]		
	PM_{10}[c] Short	PM_{10} Annual	NO_x[d]
BLR6_VRT (Boiler 2 existing)	-0.14	-0.079	-1.1
B8GS_VRT (Boiler 1 existing for natural gas)	NA	-0.0064	-0.30
B8OL_VRT (Boiler 1 existing for #6 oil)	-3.3	-2.7	-10.3
BLR6_8 (combined Boiler 1 and 2)	5.7	5.7	61.9 (41.6[e])

a. Boilers 1 and 2 operating at permitted allowable for No. 6 oil, Boiler 3 not operating
b. Pounds per hour
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
d. Oxides of nitrogen
e. Value used in Coal Creek analyses - this value differs from the DEQ value because of differences in calculated permit allowable emissions

Table 11. CRITERIA POLLUTANT EMISSION RATES USED FOR MODELING OF SCENARIO #6 OIL – 3[a]

Emission Point	Rate Used for Modeling (lb/hr)[b]		
	PM_{10}[c] Short	PM_{10} Annual	NO_x[d]
BLR6_VRT (Boiler 2 existing)	-0.14	-0.079	-1.1
B8GS_VRT (Boiler 1 existing for natural gas)	NA	-0.0064	-0.30
B8OL_VRT (Boiler 1 existing for #6 oil)	-3.3	-2.7	-10.3
BLR6_8 (combined Boiler 1 and 2)[e]	2.1	2.1	23.1 (16.1[f])

a. Boilers 1 operating at permitted allowable for No. 6 oil, Boiler 2 not operating, Boiler 3 operating at permitted allowable rate
b. Pounds per hour
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
d. Oxides of nitrogen
e. Reduced flow from Boiler 2 not operating; emissions equal to permit limit for Boiler 1
f. DEQ value differs from submitted value because lb/hr NO_x emission differences

Table 12. CRITERIA POLLUTANT EMISSION RATES USED FOR MODELING OF SCENARIO #2 OIL – 1[a]

Emission Point	Rate Used for Modeling (lb/hr)[b]		
	PM_{10}[c] Short	PM_{10} Annual	NO_x[d]
BLR6_VRT	-0.14	-0.079	-1.1
B8GS_VRT	NA	-0.0064	-0.30
B8OL_VRT	-3.3	-2.7	-10.3
BLR6_8	0.75	0.75	18.2

a. Boilers 1 and 2 operating at permitted allowable for No. 2 oil, Boiler 3 not operating.
b. Pounds per hour
c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
d. Oxides of nitrogen

Table 13. NO_x EMISSION RATES FROM BOILERS FOR FULL IMPACT ANALYSES

Operational Scenario / Emission Point	NO_x Emission Rate Used for Modeling (lb/hr)[a]
#6 Oil - 1	
BLR6_8	61.9
#6 Oil – 3	
BLR7	5.25
BLR6_8	23.1
#2 Oil - 1	
BLR6_8	18.2

a. Pounds per hour

3.2.4 Emission Rates for TAPs Included in the Modeling Analyses

The difference between current actual TAP emissions and future allowable TAP emissions were used to evaluate the need for modeling TAPs, as per IDAPA 58.01.01.210.05. The submitted application referred to this approach as "netting." However, "net emission increase" for TAPs is defined by IDAPA 58.01.01.007.06 as those emissions increases and decreases occurring from July 1, 1995.

Table 14 lists TAP emissions rates modeled for each operational scenario where emission increases associated with the modification, for either controlled or uncontrolled emissions, exceeded the applicable screening emission levels (ELs).

Table 14. TAP EMISSIONS RATES MODELED

Operational Scenario / Emission Unit	Controlled TAP emission increase modeled (lb/hr[a])							
	As[b]	Cd[c]	Cr6[d]	Ni[e]	Be[f]	V2O5[g]	Form.[h]	POM[i]
#6 Oil – 1 / BLR6_8	1.19E-4		2.08E-5	8.14E-3		5.54E-3	1.43E-2	5.06E-6
#6 Oil – 3 / BLR6_8		1.66E-5			1.09E-4		1.00E-2	
#2 Oil – 1 / BLR6_8		4.34E-5			1.80E-4		3.04E-2	

a. Pounds per hour
b. Arsenic
c. Cadmium
d. Hexavalent chromium
e. Nickel
f. Beryllium
g. Vanadium as V2O5
h. Formaldehyde
i. Policyclic organic matter

3.3 Emission Release Parameters

Table 15 provides emissions release parameters, including stack location, stack height, stack diameter, exhaust temperature, and exhaust velocity.

Table 15. EMISSIONS AND STACK PARAMETERS

Release Point / Operational Scenario	Stack Location in UTM (m)[a]		Stack Height (m)	Modeled Diameter (m)	Stack Gas Temp. (K)[b]	Stack Gas Flow Velocity (m/sec)[c]
BLR6_VRT	E387801.0[d]	N4783975[d]	15.2	1.1	422	9.6
BLR6_GAS	E387801.0[d]	N4783975[d]	15.2	1.1	422	13.3
BLR7	E387794.3	N4783961	13.4	0.85	519	15.4
B8GS_VRT	E387828.4	N4783966	30.5	1.1	422	10.0
B8OL_VRT	E387828.4	N4783966	30.5	1.1	408	6.4
BLR6_8	E387828.4	N4783966	30.5	1.1	320	15.2 (5.68[e]) (20.1[f])
BLR8_GAS	E387828.4	N4783966	30.5	1.1	320	10.0

a Meters
b Kelvin
c Meters per second
d Location corrected by DEQ. Originally submitted modeling incorrectly positioned the stack at the same location as B8GS_VRT, B8OL_VRT, BLR6_8, and BLR8_GAS
e Flow when only Boiler 1 operating
f Flow when firing No. 2 oil

3.4 Results

3.4.1 Significant Impact Analyses

Table 16 summarizes the results of the significant impact analyses. A full impact analysis, including facility-wide emissions, was needed for NO_x because the maximum modeled impact of the proposed sources exceeded SCLs.

Table 16. RESULTS OF SIGNIFICANT IMPACT ANALYSES

Pollutant / Operating Scenario	Averaging Period	Year	Maximum Modeled Concentration[a] ($\mu g/m^3$)[b]	Significant Contribution Level ($\mu g/m^3$)	Facility-Wide Modeling Required
PM_{10}[c]					
#6 Oil - 1	24-hour	1987	3.1 (3.1)	5.0	No
	Annual	1991	0.51 (0.53)	1.0	No
#6 Oil - 3	24-hour	1987	1.7	5.0	No
	Annual	1988	0.133	1.0	No
NO_2[d]					
#6 Oil - 1	Annual	1991	7.3 (8.3)	1.0	Yes
#6 Oil - 3	Annual	1991	3.4 (4.2)	1.0	Yes
#2 Oil - 1	Annual	1991	(2.7)	1.0	Yes

a Values in parentheses are modeling results obtained by Coal Creek
b Micrograms per cubic meter
c Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
d Nitrogen dioxide – value assumed to be 75 % of the modeled NO_x value

3.4.1 Full Impact Analyses

Table 17 summarizes the NO_2 full impact analyses. All modeled concentrations, when combined with a conservative background concentration, were well below the applicable NAAQS. Results obtained from DEQ verification modeling were substantially larger than those obtained by Coal Creek. Review of the modeling files indicated Coal Creek modeled facility-wide emissions with impacts of existing boiler operations subtracted out. Since facility-wide modeling is performed to assess impacts of emissions from the entire facility, impacts from previous actual emissions should not be disregarded.

Table 17. RESULTS OF THE NO_2 FULL IMPACT ANALYSES

Operating Scenario	Averaging Period	Year	Maximum Modeled Concentration[a] ($\mu g/m^3$)[b]	Background Concentration ($\mu g/m^3$)	Total Ambient Concentration ($\mu g/m^3$)	Percent of 100 $\mu g/m^3$ NAAQS
#6 Oil - 1	Annual	1991	20.4 (12.9)	17	37.4 (29.9)	37
#6 Oil - 3	Annual	1990	13.6 (11.2)	17	30.6 (28.2)	31
#2 Oil - 1	Annual	1988	(6.4)	17	(23)	23

[a] Nitrogen dioxide values assumed to be 75% of the modeled NO_x value - values in parentheses are modeling results obtained by Coal Creek

[b] Micrograms per cubic meter

3.4.2 TAP Analyses

Table 18 summarizes the ambient TAP analyses. Maximum annual impacts of controlled carcinogenic TAPs were well below applicable AACCs, thereby demonstrating preconstruction TAP compliance via IDAPA 58.01.01.210.08 (Controlled Ambient Concentration). DEQ did not conduct verification analyses for TAPs because model results obtained by Coal Creek were less than half the allowable increment for all TAPs. Uncontrolled emissions of all non-carcinogenic TAPs were below the screening emission levels (ELs), below which dispersion modeling is not required.

Table 18. RESULTS OF TAP ANALYSES

TAP	Averaging Period	Year	Maximum Modeled Concentration ($\mu g/m^3$)[a]	AACC ($\mu g/m^3$)	Percent of AACC
#6 Oil – 1					
POM	Annual	1991	<0.00001	0.45	<0.002
Formaldehyde	Annual	1991	0.00330	0.077	4
Arsenic	Annual	1991	0.00003	0.00023	13
Chromium VI	Annual	1991	0.00001	0.00008	13
Nickel	Annual	1991	0.00193	0.00420	46
Vanadium	24-hour	1987	0.0101	2.5	0.4
#6 Oil – 3					
Formaldehyde	Annual	1988	0.00101	0.077	1.3
Beryllium	Annual	1990	0.00001	0.0042	0.2
Cadmium	Annual	1991	0.00001	0.00056	1.8
#2 Oil – 1					
Formaldehyde	Annual	1991	0.00504	0.0770	6.5
Beryllium	Annual	1991	0.00003	0.0042	0.7
Cadmium	Annual	1991	0.00001	0.00056	1.8

[a] Micrograms per cubic meter

3.5 *Additional DEQ Analyses*

Two supplemental analyses were performed by DEQ to verify NAAQS compliance.

3.5.1 Impact of Total Emissions from Boiler Operational Scenarios

DEQ conducted an analysis similar to the significant impact analysis for operational scenario #6 Oil – 1 (Boilers 1 and 2 operating continuously on No. 6 oil), except the impact of total emissions was assessed rather than the emission increase associated with the proposed project. These analyses were conducted to ensure the operation of the equipment as proposed will not, by itself, cause an exceedance of NAAQS.

Table 19 summarizes the results of the modeling analyses.

Table 19. RESULTS OF THE DEQ TOTAL BOILER IMPACT ANALYSES

Pollutant / Operating Scenario	Averaging Period	Year	Maximum Modeled Concentration ($\mu g/m^3$)[a]	Background Concentration ($\mu g/m^3$)	Total Ambient Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of NAAQS
PM_{10}							
#6 Oil - 1	24-hour	1990	7.9	73	80.9	150	54
	Annual	1991	1.13	26	27.1	50	54
NO_2							
#6 Oil - 1	Annual	1991	9.2	17	26.2	100	26

a. Micrograms per cubic meter

3.5.2 BAF/Nonpariel Combined NO_2 Impacts

DEQ had concerns that impacts from the neighboring Nonpariel Corporation facility would not be accounted for in the background concentrations used in the full impact analysis. NO_x emissions from the Nonpariel facility were modeled along with BAF's emissions to ensure combined impacts were below the 100 $\mu g/m^3$ NAAQS. The NO_x emissions inventory for Naonpariel was obtained from a recently submitted facility-wide Tier II permit application and is listed in Appendix A. This modeling was conducted for BAF operational scenario #6 Oil – 1 and was modeled for 1991 only. Modeling results for NO_2 from combined emissions of BAF and Nonpariel are summarized in Table 20.

Table 20. RESULTS OF COMBINED BAF/NONPARIEL
NO2 FULL IMPACT ANALYSES

Operating Scenario	Averaging Period	Year	Maximum Modeled Concentration[a] ($\mu g/m^3$)[b]	Background Concentration ($\mu g/m^3$)	Total Ambient Concentration ($\mu g/m^3$)	Percent of 100 $\mu g/m^3$ NAAQS
#6 Oil - 1	Annual	1991	17.6	17	34.6	35

a. Nitrogen dioxide values assumed to be 75% of the modeled NO_x
b. Micrograms per cubic meter

4.0 CONCLUSIONS

The air quality analyses submitted with the PTC application, in combination with DEQ's analyses, demonstrated to DEQ's satisfaction that the proposed modification will not cause or significantly contribute to an exceedance of any air quality standard, as required by IDAPA 58.01.01.203.02.

APPENDIX A

BAF AND NONPARIEL FACILITY-WIDE NO_X EMISSIONS USED IN MODELING

BAF AND NONPARIEL FACILITY-WIDE NO_X EMISSIONS USED IN MODELING

Source ID	Facility	Easting (X) (m)	Northing (Y) (m)	Base Ele (m)	Stack Height (m)	Temp (K)	Exit Vel (m/s)	Stack Dia. (m)	NO_X-ANN (lb/hr)
BLR6_8	BAF	387828.4	4783966	1363.4	30.48	319.82	15.229	1.07	61.9
AEV	BAF	387763.8	4783921	1363.4	15.5204	299.82	16.827	0.814	0.1683
CBB	BAF	387802.6	4783908	1363.4	11.7348	327.59	12.25	0.585	0.0765
CHX	BAF	387779.7	4783917	1363.4	12.2926	360.93	8.46	0.972	0.4323
CHY	BAF	387784.1	4783917	1363.4	9.5738	348.15	7.481	0.631	0.1613
CHZ	BAF	387789.4	4783917	1363.4	10.921	359.26	4.541	0.555	0.0796
CNV	BAF	387825	4783899	1363.5	19.5072	477.59	26.663	0.914	0.612
CNW	BAF	387818.1	4783899	1363.4	19.5072	477.59	26.663	0.914	0.612
CTQ	BAF	387801.4	4783903	1363.4	11.177	343.71	12.16	0.594	0.2093
CTR	BAF	387798.3	4783903	1363.4	10.8204	330.37	21.058	0.396	0.1779
CTS	BAF	387795	4783903	1363.4	10.8204	329.26	11.767	0.338	0.0744
CTT	BAF	387788.1	4783902	1363.4	10.8204	323.15	13.63	0.338	0.0892
CXX	BAF	387825.5	4783923	1363.5	12.573	323.15	17.746	0.762	0.5822
CYY	BAF	387826.1	4783917	1363.6	14.0452	320.93	0.001	0	0.3527
DHT	BAF	387762	4783952	1363.4	15.3162	333.15	22.377	0.914	0.539
DHU	BAF	387767.3	4783952	1363.4	20.065	333.15	22.377	0.914	0.539
DHZ	BAF	387769.4	4783957	1363.4	20.065	330.37	13.511	0.914	0.306
DQA	BAF	387764.9	4783937	1363.4	19.4554	333.15	14.151	1.067	0.539
DQB	BAF	387756.8	4783937	1363.4	19.4554	333.15	14.151	1.067	0.539
DUQ	BAF	387764.9	4783943	1363.4	19.0256	333.15	14.995	1.067	0.539
DUT	BAF	387756.8	4783943	1363.4	19.0256	333.15	14.995	1.067	0.539
DUV	BAF	387768.5	4783938	1363.4	20.9794	330.37	15.2	1.219	0.612
HEB	BAF	387824.6	4783882	1363.5	17.8308	350.37	0.001	0	0.2911
HNL	BAF	387809.2	4783875	1363.4	6.8072	343.15	0.001	0	0.0869
TAC	BAF	387617.3	4784000	1363.3	13.716	505.37	14.068	0.387	0.06375
TAH	BAF	387617.3	4784003	1363.3	13.716	505.37	12.192	0.415	0.06375
TCD	BAF	387631.3	4784028	1363.7	9.906	337.59	0.001	0	0.102
EU_01	Nonpar	388318	4784088	1365	12.4968	483.15	11.491	0.701	14.85
EU_02	Nonpar	388313	4784088	1365	12.4968	483.15	6.767	0.914	1.99
EU_03	Nonpar	388351.6	4784018	1365	8.5344	306.48	9.053	0.610	0.412
EU_04	Nonpar	388373.6	4784098	1365	13.716	306.48	16.916	0.853	0.539
EU_20	Nonpar	388071.5	4783957	1364	8.5344	466.48	6.157	0.488	1.029
EU_21	Nonpar	388069.9	4783953	1364	8.5344	466.48	1.402	0.914	0.824
EU_22	Nonpar	388100.4	4783938	1364	10.9728	359.26	12.436	0.762	0.627
EU_23	Nonpar	388115	4783937	1364	9.144	338.71	5.761	0.914	0.275
EU_24	Nonpar	388094.3	4783938	1364	10.9728	359.26	12.436	0.762	0.627
EU_25	Nonpar	388106.5	4783928	1364	9.144	338.71	5.761	0.914	0.275
EU_26	Nonpar	388090	4783926	1364	10.9728	359.26	12.436	0.762	0.627
EU_27	Nonpar	388104	4783921	1364	9.144	338.71	8.291	0.762	0.275
EU_28	Nonpar	388085.7	4783915	1364	7.0104	344.26	10.363	0.762	0.468
EU_29	Nonpar	388093	4783913	1364	7.0104	338.71	6.462	0.610	0.032
EU_30	Nonpar	388105.6	4783910	1364	7.0104	327.59	3.993	0.549	0.029
EU_31	Nonpar	388083.7	4783910	1364	8.2296	344.26	14.569	1.036	1.020
EU_32	Nonpar	388100.8	4783906	1364	8.2296	338.71	10.516	0.792	0.314
EU_33	Nonpar	388106.9	4783905	1364	8.2296	327.59	11.339	0.610	0.324
EU_39	Nonpar	388146	4783830	1364	7.3152	308.15	0.001	0.152	0.086
EU_01_NG	Nonpar	388318	4784088	1365	12.4968	483.15	11.491	0.701	1.985
EU_02_NG	Nonpar	388313	4784088	1365	12.4968	483.15	6.767	0.914	1.985